RAILROAD COMMISSION OF TEXAS
GAS SERVICES DIVISION

GAS UTILITIES
INFORMATION BULLETIN

No. 691

RAILROAD COMMISSION
OF TEXAS

Michael L. Williams, Chairman
Charles R. Matthews, Commissioner
Tony Garza, Commissioner

Steve Pitner
Director
Gas Services Division

January 10, 2002

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Final Orders signed in Gas Utilities Docket No 9217 Enforcement Action Against TXU Gas Distribution for Violation of Commission Statewide Pipeline Safety Rules and Violation of Commission Consent Order in Docket No.s 9186, and Gas Utilities Docket No. 9234 - Statement of Intent filed by Natgas Inc to increase rates in the community of Ozona, TX.

SECTION 1
NEW APPEALS AND APPLICATIONS FILED

DOCKET NO.	**--**	9260
CAPTION	**--**	Statement of Intent filed by Gaylyn, Inc. to increase the city gate rate charged to Dal-Mar Energy, Inc.
DATE FILED	**--**	December 11, 2001
FILED BY	**--**	Rick Potter
EXAMINER	**--**	

DOCKET NO.	**--**	9261
CAPTION	**--**	Application of EPGT Texas Pipeline, L.P. for review of the merger with EPGT Texas LDC, L.P.
DATE FILED	**--**	December 10, 2001
FILED BY	**--**	Joseph D. Naylor
EXAMINER	**--**	Mimi Winetroub

DOCKET NO.	**--**	9262
CAPTION	**--**	Application of EPGT Texas Pipeline, L.P. for review of merger with Seahawk Transmission Company.
DATE FILED	**--**	December 11, 2001
FILED BY	**--**	Joseph D. Naylor
EXAMINER	**--**	Mimi Winetroub

DOCKET NO.	**--**	9263
CAPTION	**--**	Complaint of Spencer Station Generating Company L.P., against TXU Lone Star Pipeline and TXU Gas Distribution for failure to provide gas utility service on reasonable terms.
DATE FILED	**--**	December 14, 2001
FILED BY	**--**	G. Gail Watkins
EXAMINER	**--**	

DOCKET NO.	**--**	9264
CAPTION	**--**	Request of Houston Pipe Line Company for waiver of plan time schedule for integrity assessment.
DATE FILED	**--**	December 14, 2001
FILED BY	**--**	Elizabeth S. Bush-Ivie, P.E.
EXAMINER	**--**	

SECTION 2
APPEALS AND APPLICATIONS SET FOR HEARING OR PREHEARING CONFERENCE

None at this time.

SECTION 3
STATUS OF PENDING CASES

None at this time.

SECTION 4
NOTICES OF DISMISSAL

None at this time.

SECTION 5
ORDERS OF THE COMMISSION

ENFORCEMENT ACTION AGAINST	**§**	
TXU GAS DISTRIBUTION FOR	**§**	
VIOLATION OF COMMISSION	**§**	**GAS UTILITIES DOCKET NO. 9217**
STATEWIDE PIPELINE SAFETY RULES	**§**	
AND VIOLATION OF COMMISSION	**§**	
CONSENT ORDER IN DOCKET NO. 9186	**§**	

CONSENT ORDER

On this the 20th day of December, 2001, the above-captioned docket came on for consideration by the Railroad Commission of Texas ("Commission"). The Commission and TXU Gas Distribution ("TXU") have agreed to an informal disposition of the matters under this docket through this Consent Order. The Commission has authority to informally dispose of this contested case docket through a consent order pursuant to TEX. GOVT. CODE ANN. § 2001.056(3).

IN COMPROMISE AND SETTLEMENT OF THE MATTERS AT ISSUE IN THIS DOCKET, the Commission and TXU do hereby agree and stipulate as follows:

1. TXU is a "gas utility" as that term is defined in TEX. UTIL. CODE §121.001 and is subject to the jurisdiction of the Commission pursuant to TEX. UTIL. CODE §121.201.

2. For the purposes of TEX. UTIL. CODE, Chapter 121, Subchapter E, TXU is a "person" as that term is defined by 16 TEX. ADMIN. CODE §7.70(b)(1).

3. TXU operates gas pipeline facilities and is engaged in the transportation of gas as defined by 16 TEX. ADMIN. CODE §7.70(b)(2), (3) and (4).

4. In 1997, TXU developed a voluntary Poly I Replacement Program ("Replacement Program") to remove all older generation polyethylene 3306 ("Poly I") pipe from its natural gas distribution facilities and replace the pipe with a newer generation of polyethylene pipe or steel pipe not later than June 30, 2002.

5. In response to the natural gas accident involving a Poly I main in Garland, Texas on January 14, 2000, TXU began to resurvey its natural gas distribution facilities for other potential Poly I locations and to remove all Poly I pipe and replace it with a newer generation of polyethylene or steel pipe not later than June 30, 2001.

6. On May 23, 2000, the Commission in Gas Utilities Docket No. 9151 ordered TXU to accelerate the Replacement Program and resurvey its natural gas distribution facilities for potential Poly I pipe and remove all such pipe and replace it with a newer generation of polyethylene or steel pipe not later than December 31, 2000.

7. By letter to the Chairman of the Commission dated December 8, 2000, TXU requested that, due to an insufficient work force being available with polyethylene expertise and due to extreme weather conditions, the Commission extend the date by which TXU is required to complete the resurvey, removal, and replacement of Poly I pipe in its natural gas distribution facilities.

8. On December 20, 2000, the Commission in Gas Utilities Docket No. 9186 granted TXU's extension request and ordered TXU to resurvey its natural gas distribution facilities for potential Poly I pipe and remove all such pipe and replace it with a newer generation of polyethylene or steel pipe as follows:

    a. mains and associated services lines, not later than April 30, 2001; and

    b. non-associated or isolated service lines, not later than December 31, 2001.

9. As ordered by the Commission, TXU has resurveyed its natural gas distribution facilities as part of its Replacement Program.

10. During the most labor intensive portion of the resurvey phase for mains and associated service lines, 727 TXU company and contract employees, including 148 field crews were dedicated to the resurvey project on a full time basis. TXU reviewed over 22,000 maps and identified more than 7942 potential Poly I locations and 949 miles of potential Poly I mains. In addition, TXU developed test hole spacing protocols that resulted in the digging of more than 102,000 test holes by TXU to identify the generation of polyethylene pipe in those locations. Based on the resurvey process which concluded on April 30, 2001, TXU replaced approximately 216 miles of main pipe and determined that approximately 733 miles were not Poly I.

11. Based on its map review, TXU identified the pipeline segments of its natural gas distribution facilities that had the potential to contain Poly I main pipe. At the time TXU installed Poly I pipe, industry standards and Commission rules did not require TXU to record the generation of polyethylene pipe in its records. In order for TXU to identify the generation of polyethylene pipe, test hole spacing protocols were developed by TXU in consultation with Commission Staff as part of the Poly I Replacement Program. The test hole spacing protocols were necessary to allow the generation of polyethylene pipe to be identified. The test hole spacing protocols required TXU to dig more than 102,000 test holes to identify the generation of polyethylene main pipe and over 70,000 test holes to identify the generation of non-associated or isolated service line polyethylene pipe.

12. During the non-associated or isolated service line phase, TXU reviewed over 7,000,000 records to identify potential Poly I non-associated or isolated service line locations and dug more than 70,000 test holes. TXU identified over 48,000 potential Poly I non-associated or isolated service lines and replaced the service lines or verified the service lines as not being Poly I.

13. TXU has submitted to the Pipeline Safety Section an amendment to its Distribution Operating Manual that includes a provision requiring immediate notification in the event of any siting of Poly I pipe in service, and the immediate replacement of any such Poly I pipe.

14. As part of the TXU continued education/training programs, all company and contract personnel who work on natural gas distribution facilities have been directed to immediately report any sitings of Poly I pipe to the local TXU supervisor and will be trained on an ongoing basis to identify Poly I pipe.

15. On April 26, 2001, TXU notified the Commission that the replacement of all Poly I mains and associated services lines identified during the Replacement Program was completed.

16. On December 11, 2001, TXU notified the Commission that the replacement of all Poly I non-associated or isolated service lines it identified was completed.

17. As of the date of this Consent Order, TXU has replaced all of the Poly I mains and associated service lines and Poly I non-associated or isolated service lines it identified in its natural gas distribution facilities as required by the Consent Orders entered in Gas Utilities Docket No. 9151 and Gas Utilities Docket No. 9186.

18. The resurvey of TXU's natural gas distribution facilities for potential Poly 1 pipe and the removal and replacement of all such pipe with a newer generation of polyethylene or steel pipe was necessary to provide service to the public and to accomplish the requirements imposed by the Consent Orders in Gas Utilities Docket No. 9186 and Gas Utilities Docket No. 9151. The protocol designed by TXU for the spacing of test holes was necessary to identify Poly I pipe in its distribution system. TXU accounted for the costs associated with the test holes as a regulatory asset pursuant to Statement of Financial Accounting Standards No. 71 - Accounting For the Effects of Certain Types of Regulation. Any recovery of the costs associated with the resurvey, removal and replacement of Poly I pipe shall be addressed in a future rate proceeding.

19. In response to a request by the Commission's Pipeline Safety Section in May 2001, TXU in consultation with Commission Staff developed a Poly I Replacement Program Audit Process ("Audit Process") to verify the safe operation of TXU's natural gas distribution facilities. As part of the Audit Process, TXU is re-reviewing over 22,000 maps and the spacing for over 102,000 test holes dug to identify the generation of polyethylene main pipe. In addition, TXU has reviewed more than 43,000 main and service line leak repair records and expenditure requisition records to identify any additional potential Poly I locations that were not identified based on the initial map review.

20. Beginning May 1, 2001, TXU has notified the Commission each time a Poly I main pipe siting occurred. To date, seventy-two sitings have been reported to the Commission.

21. The Commission alleges that TXU violated the requirements of the Consent Order in Gas Utilities Docket No. 9186 by failing

to remove all Poly I mains and associated service lines by the date stated in the Consent Order.

22. TXU denies this allegation. TXU asserts that it did not violate the requirements of the Consent Order in Gas Utilities Docket No. 9186 since TXU had replaced all Poly I mains and associated service lines it identified by the April 30, 2001 deadline set forth in the Docket No. 9186 Consent Order.

23. Neither this Consent Order, nor any written or oral offer of settlement related thereto, nor any statement contained therein shall constitute evidence or an admission or adjudication of any violation of any statute, rule or regulation or other wrongdoing or misconduct on the part of TXU or any director, officer, agent, employee, contractor or affiliate thereof. The Commission shall not use this Consent Order, any offer or settlement relating thereto, nor the Investigation as the basis for the institution of any further administrative or enforcement proceedings relating to the Poly I Replacement Program.

24. The Commission and TXU, without admission of fault or wrongdoing, mutually desire to settle this dispute and to compromise and settle all matters relating to the removal and replacement of Poly I mains and associated service lines and any sitings subsequent to April 30, 2001 and non-associated or isolated service lines and any sitings subsequent to December 31, 2001 in TXU's natural gas distribution facilities. Notwithstanding the foregoing, the Commission retains the right to bring an enforcement action relating to Poly I pipe based upon a pipeline safety rule violation which involves an incident or accident resulting in property damage or death or injury to persons.

25. The Commission and TXU wish to further the shared goal of safe operation of gas pipeline facilities within the State of Texas.

26. The person signing hereunder for TXU has authority to represent TXU in this docket.

The Commission **ORDERS** that TXU shall continue to meet at least once a month with the Commission's Pipeline Safety Staff to provide an update of the Audit Process. These monthly meetings shall continue until such time as the Commission's Pipeline Safety Staff determines that the meetings are no longer necessary.

The Commission further **ORDERS** that if additional segments of Poly I pipe in service are identified after the date of this order that TXU Gas Distribution shall notify the Pipeline Safety Section within 24 hours of the identification of such Poly I pipe. The Commission further **ORDERS** TXU to take immediate action to remove all Poly I pipe in service which is identified after the date of this order and to replace it with a newer generation of polyethylene or steel pipe.

Jurisdiction of the Commission over this docket having been established and based on the evidence in the record and agreement of the parties and in compromise and settlement of all matters relating to the removal and replacement of Poly I mains and associated service lines, including any sitings subsequent to April 30, 2001, and non-associated or isolated service lines, including any sitings subsequent to December 31, 2001, in TXU's natural gas distribution facilities, the Railroad Commission of Texas further **ORDERS** TXU Gas Distribution to pay an administrative penalty in the amount of $225,000, and that Gas Utilities Docket No. 9217 be disposed by this Order and closed. All relief not granted in this Order is **DENIED**.

SIGNED THIS 20th DAY of DECEMBER 2001.

RAILROAD COMMISSION OF TEXAS

/s/ Michael L. Williams, Chairman

(Not signed) Charles R. Matthews, Commissioner

/s/ Tony Garza, Commissioner

Attest:
/s/ Kim Williamson
Secretary

APPROVED AS TO FORM AND SUBSTANCE
/s/ Phil Gamble
Attorney for TXU Gas Distribution

STATEMENT OF INTENT FILED BY NATGAS INC TO INCREASE RATES IN THE COMMUNITY OF OZONA, TX	' ' ' '	**GAS UTILITIES DOCKET NO. 9234**

FINAL ORDER

Notice of Open Meeting to consider this Order was duly posted with the Secretary of State within the time period provided by law pursuant to TEX. GOV'T CODE ANN. Chapter 551 *et seq.* (Vernon 1994 & Supp. 2001). The Railroad Commission of Texas adopts the following findings of fact and conclusions of law and orders as follows:

FINDINGS OF FACT

1. Natgas, Inc., (Natgas) owns and operates a natural gas distribution system in the unincorporated community of Ozona, Texas.

2. On July 31, 2001, Natgas filed with the Railroad Commission of Texas (Commission) a Statement of Intent to increase its rates within the unincorporated community of Ozona, Texas.

3. Natgas requested an effective date of September 3, 2001.

4. On August 21, 2001, the Commission suspended the implementation of Natgas' proposed rates for 150 days beyond the proposed effective date, or until January 31, 2002.

5. Natgas provided adequate notice to customers by publishing notice four consecutive times in the Ozona Stockman prior to September 3, 2001.

6. Crockett County filed a protest but did not intervene as a party and no hearing was conducted on this matter.

7. Natgas sought an area-wide base revenue of $819,640.

8. After review of the proposed revenue requirement, Natgas is currently seeking an area-wide base revenue of $626,165.

9. Natgas proposed a cost of service of $360, 254. After review, a $315,320 cost of service was found to be reasonable.

10. The data submitted to the Commission in this docket encompasses a full test-year, *i.e.*, the twelve-month period ending December 31, 2000.

11. Under the proposed rate design, Natgas will have rates for two customer classes: Large Commercial Customer and General Customer.

12. Under the proposed rate increase, the General Customer Rate will consist of a minimum bill of $5.00 and a volumetric charge of $6.17 per Mcf, plus a cost of gas component to be determined in accordance with the Gas Cost Rider attached hereto as Exhibit A.

13. Under the proposed rate increase, the Large Commercial Customer Rate will consist of a minimum bill of $5.00 and a volumetric charge of $5.85 per Mcf, plus a cost of gas component to be determined in accordance with the Gas Cost Rider.

14. The rates proposed by Natgas and described in Findings of Fact Nos. 11 and 12 are just and reasonable.

15. The current service fees and deposit charges reflected in the current tariff on file with the Railroad Commission remain unchanged.

16. Natgas has requested that rates be made effective January 1, 2002, instead of the date that this Order is signed and allowing such an effective date is reasonable.

CONCLUSIONS OF LAW

1. Natgas is a gas utility as defined in TEX. UTIL. CODE ANN. §101.003(7) and TEX. UTIL. CODE ANN. §121.001 (Vernon Supp. 2001) and is subject to the Commission's jurisdiction under TEX. UTIL. CODE ANN. §§104.002 and 121.051 (Vernon 1998).

2. The Commission has exclusive original jurisdiction over Natgas and Natgas' application under TEX. UTIL. CODE ANN.§102.001 (Vernon 1998).

3. The revenue, rates and rate design recommended in the findings of fact are just and reasonable, are not unreasonably preferential, prejudicial, or discriminatory, and are sufficient, equitable, and consistent in application to each class of consumers, as required by TEX. UTIL. CODE ANN. §104.003 (Vernon 1998).

4. The revenue, rates, and rate design recommended in the findings of fact are reasonable and fix an overall level of revenues for Natgas that will permit Natgas a reasonable opportunity to earn a reasonable return on its invested capital used and useful in rendering service to the public over and above its reasonable and necessary operating expenses under TEX. UTIL. CODE ANN. §104.051 (Vernon 1998), and otherwise comply with Chapter 104 of the Texas Utilities Code.

5. The revenue, rates, and rate design recommended in the findings of fact will not yield to Natgas more than a fair return on the adjusted value of the invested capital used and useful in rendering service to the public, as required by TEX. UTIL. CODE ANN. §104.052 (Vernon 1998).

6. Natgas has met its burden of proving that the proposed rates are just and reasonable, under TEX. UTIL. CODE ANN. §104.008 (Vernon 1998).

7. It is reasonable for the Commission to allow Natgas to include a cost of gas clause in its tariffs that allows the recovery of Natgas' gas costs, under 16 TEX. ADMIN. CODE §7.55 (West 2001).

8. It is reasonable to allow the company's increased rates to be made effective January 1, 2002, pursuant to 16 TEX. ADMIN. CODE § 7.54 (West 2001).

IT IS THEREFORE ORDERED BY THE RAILROAD COMMISSION OF TEXAS THAT Natgas' rates as reflected in the findings of fact are **HEREBY APPROVED** to be charged for gas delivered on or after January 1, 2002. These rates shall apply only in the unincorporated areas of Ozona served by Natgas as of the date of this order, and shall not apply to any system that Natgas acquires from another utility after the date of this order.

IT IS FURTHER ORDERED THAT Natgas shall include in its cost of gas charge only its reasonable and necessary gas purchase expenditures and that the reasonableness and prudence of Natgas' gas purchases pursuant to its cost of gas clause are subject to reconciliation and adjustment and potential refunding in a subsequent proceeding.

IT IS FURTHER ORDERED THAT within 20 days of this order Natgas shall file tariffs and rate schedules in proper form that accurately reflect the rates approved by the Commission in this proceeding.

IT IS ORDERED THAT all proposed Findings of Fact and Conclusions of Law not specifically adopted herein are **DENIED**.

SIGNED this 8th day of January, 2002.

RAILROAD COMMISSION OF TEXAS

/s/______________________________________
CHAIRMAN MICHAEL L. WILLIAMS

/s/____
COMMISSIONER CHARLES R. MATTHEWS

/s/ _______________________________________
COMMISSIONER TONY GARZA
ATTEST:

/s/Kim Williamson
SECRETARY

SECTION 6
MISCELLANEOUS

STEVE PITNER, GAS SERVICES DIVISION DIRECTOR

1. OFFICE OF THE DIRECTOR

A. Publications

1. Texas Utilities Code Titles 3 and 4. Special Rules of Practice and Procedure and Substantive Rules - $15.00

2. a. Annual Report for Fiscal Year 2000 - $17.00 (includes statistical data for 1999)

   b. Annual Report for Fiscal Year 1999 - $9.00 (includes statistical data for 1998)

   c. Annual Report for Fiscal Year 1998 - $7.00 (includes statistical data for 1997)

3. January 2000 Pipeline Safety Rules - $24.00, includes: 49 CFR 191 & 192 and 16 TAC Sections 7.70-7.74 (gas) 49 CFR 193 (LNG); 49 CFR 195 and 16 TAC Sections 7.80-7.87 (hazardous liquids); 49 CFR 40 and 199 (drug testing).

4. Distribution and/or Gas Transmission Review forms for Adequacy of Operation, Maintenance and Emergency Manual - To obtain a copy of review forms at no charge, send a request with a self addressed envelope (10" x 13"preferably) with $0.98 postage.

5. Six MCF Monthly Residential Gas Bill Analysis for Twenty-five Texas Cities - $2.00

Anyone who wishes to obtain a copy of any of the publications or maps listed in Section A should contact the Gas Services Division, P. O. Box 12967, Austin, Texas 78711-2967, (512) 463-7167.

B. Interest Rate on Customer Deposits

We have been advised by the Public Utility Commission that the interest rate to be applied to customer deposits in calendar year 2002 is 6.00%. All gas utilities should use this rate.

2. PIPELINE SAFETY SECTION

A. Austin Headquarters - William B. Travis Building
1701 North Congress, (78701)
PO Box 12967
Austin, Texas 78711-2967 Telephone (512) 463-7058

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William (Bill) Dase, Jr., P.E., Engineer
Terry Pardo, P.E., Engineer
K. David Born, Field Operations Manager
William (Bill) Meyer, Compliance Manager
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Amarillo Region 1 - 7102 IH-40 West, Bldg. C., Amarillo, Texas 79106 Telephone (806) 468-7486

Scott Williamson, Engineering Specialist
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Don Gault, Area Supervisor
Steven Schmidt, Engineering Specialist
Steven Rios, Engineering Assistant
Jesse Cantu, Jr., Engineering Assistant

B. Monthly Summary (October)

No. of distribution safety evaluations - 95
No. of transmission safety evaluations - 150
No. of liquid safety evaluations - 58
No. of leak/calls - 62
No. of accident investigations - 22
No. of special investigations - 23

C. Reporting of Pipeline Accidents

1) NATURAL GAS

Accidents on intrastate gas systems involving $5,000 property damage, a fatality or injuries, gas ignition, or that are judged significant must be reported by telephone within two hours, and the written report filed within thirty (30) days. Call the 24-hour emergency phone number (512)463-6788 to report an accident. For your convenience this priority phone line is used only to report emergencies.

2) HAZARDOUS LIQUIDS

Accidents on intrastate hazardous liquid pipelines reportable under 49 CFR Sections 195.50 and 195.52 and 16 TAC Section 7.84(a) must be reported by telephone within two hours and the required written report filed within thirty (30) days. Call the 24-hour emergency phone number (512)463-6788 to report an accident. For your convenience this priority phone line is used only to report emergencies.

Rules and Regulations:

[Federal Register: December 27, 2001 (Volume 66, Number 248)]
[Rules and Regulations]
[Page 66993-67007]
From the Federal Register Online via GPO Access [wais.access.gpo.gov]
[DOCID:fr27de01-34]

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Part III

Department of Transportation

Research and Special Programs Administration

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49 CFR Part 195

Controlling Corrosion on Hazardous Liquid and Carbon Dioxide Pipelines;
Final Rule

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DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

49 CFR Part 195

[Docket No. RSPA-97-2762; Amdt. 195-73]
RIN 2137-AD24

Controlling Corrosion on Hazardous Liquid and Carbon Dioxide
Pipelines

AGENCY: Research and Special Programs Administration (RSPA), DOT.

ACTION: Final rule.

SUMMARY: This Final Rule makes changes in some of the corrosion control standards for hazardous liquid and carbon dioxide pipelines. The changes are based on our review of the adequacy of the present standards compared to similar standards for gas pipelines and acceptable safety practices. The changes are intended to improve the clarity and effectiveness of the present standards, and reduce the potential for pipeline accidents due to corrosion.

DATES: This Final Rule takes effect January 28, 2002. The incorporation by reference of the publication listed in the rule is approved by the Director of the Federal Register January 28, 2002.

Compliance dates: Under Sec. 195.563(c), operators of certain effectively coated buried piping in breakout tank areas or pump stations are not required to cathodically protect that piping until December 29, 2003. Under Sec. 195.567(a), operators of cathodically protected pipelines or pipeline segments that lack test leads for external corrosion control are not required to install test leads until December 29, 2004. Under Sec. 195.573(a)(2), operators are not required to determine the circumstances in which a close-interval survey or comparable technology is practicable and necessary until December 29, 2003. Under Sec. 195.573(b), operators of unprotected pipe are not required to reevaluate the need for corrosion control on the pipe at least every 3 years until December 29, 2003.

FOR FURTHER INFORMATION CONTACT: L. M. Furrow by phone at 202-366-4559, by fax at 202-366-4566, by mail at U.S. Department of Transportation, 400 Seventh Street, SW., Washington, DC 20590, or by E-mail at buck.furrow@rspa.dot.gov.

SUPPLEMENTARY INFORMATION:

Background

Corrosion causes a significant proportion of hazardous liquid pipelines accidents. Based on this finding, we reviewed the corrosion control standards in 49 CFR part 195 to determine if the standards need to be made clearer, more effective, or consistent with acceptable safety practices. We believe that improving the standards will have the potential to reduce the number of accidents caused by corrosion.

The review began September 8, 1997, when we held a public meeting in Oak Brook, Illinois to discuss how part 195 corrosion control standards and the corrosion control standards for gas pipelines in 49 CFR part 192 might be improved (62 FR 44436; Aug. 21, 1997). We held the public meeting in conjunction with meetings of National Association of Corrosion Engineers International (NACE), a professional technical society dedicated to corrosion control. Participants agreed, universally, that part 192 and part 195 corrosion control standards are largely sufficient, and although some changes may be needed, the standards should remain generally unchanged.

Based on this conclusion, we began to consider whether the more comprehensive part 192 gas standards, possibly with some changes, would be appropriate for part 195's hazardous liquid and carbon dioxide pipelines. We met then, from time to time, with representatives of NACE, the pipeline industry, and state pipeline safety agencies for technical input. At these meetings, we also examined whether the part 192 standards need to be more effective or clearer. The meetings raised various concerns about the effectiveness and clarity of some of the part 192 corrosion control standards and the suitability of applying those standards to hazardous liquid and carbon dioxide pipelines. We also took into account that the National Association of Pipeline Safety Representatives, the Gas Piping Technology Committee, and the National Transportation Safety Board had at various times recommended changes to part 192 and part 195 corrosion control standards. So, to gather public comment on our concerns and the changes these organizations recommended, we held another public meeting on April 28, 1999, in San Antonio, Texas, and invited the public to submit written comments. The comment period remained open until June 30, 1999 (64 FR 16885; April 7, 1999).

Notice of Proposed Rulemaking

Sixty-two persons filed written comments in response to the San Antonio meeting notice. We then summarized these comments in a notice of proposed rulemaking (NPRM) published last year (65 FR 76968; Dec. 8, 2000). The NPRM proposed to add to part 195 a new subpart H called Corrosion Control. Subpart H would prescribe corrosion control standards for all new and existing steel pipelines to which part 195 applies. At this time, we also decided to address the concerns, recommendations, and comments that pertain primarily to the corrosion control standards in part 192 in a separate notice of proposed rulemaking on gas pipelines.

Although there was little support in the record for allowing NACE Standard RP0169-96, ``Control of External Corrosion on Underground or Submerged Metallic Piping Systems,'' to serve as an alternative to standards proposed in subpart H, we specifically requested further comment on this issue due to NACE's standing in the field of corrosion.

Unfortunately, no one commenting on the NPRM responded to that request, perhaps because of earlier discussions of the issue in Oak Brook and San Antonio. While NACE urged us to reference the entire NACE Standard, not just section 6 as we proposed, NACE did not assert that the NACE Standard could serve as an acceptable alternative to proposed subpart H.

The NPRM discussed each of the standards proposed for inclusion in subpart H. Many of these standards are identical to present corrosion control requirements in part 195, and many of the standards are substantially like the present requirements in part 192. Proposed subpart H also includes standards that, while based on present part 192 requirements, include changes which we think are beneficial improvements.

Discussion of Comments

We received comments from the following entities in response to the NPRM: Alberta Energy Company (AEC), City of Dallas Water Utilities, Enron Transportation Services Company (Enron), Environmental Defense, Equilon Pipeline Company (Equilon), L.A. ``Roy'' Bash, NACE, Phillips Pipe Line Company (Phillips), State of Iowa Utilities Board (Iowa), State of Washington Utilities and Transportation Commission (WUTC), and Tosco Corporation (Tosco). Most commenters supported the rulemaking, and all but the City of Dallas recommended changes to some of the proposed standards.

The City of Dallas related its experience with a major pipeline spill caused partly by corrosion. Gasoline containing MTBE, a fuel oxygenate which effects the taste and odor of water, entered a lake resulting in a water supply crisis. The City stated that it is critical for DOT to adopt rules to require

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all pipelines, especially those transporting gasoline with MTBE near a municipal water resource, to be regularly monitored for corrosion, cracks, and leaks; and that any deficiencies found, be timely repaired.

This rulemaking will accomplish what the City of Dallas is seeking with respect to corrosion. In particular, Secs. 195.573, 195.579, and 195.583 will require operators to monitor pipelines regularly for corrosion and correct any deficiencies found in corrosion control. Additionally, new Sec. 195.585 specifies corrective action for any harmful corrosion found. The timeliness of correcting corrosion control deficiencies and harmful corrosion is covered by existing Secs. 195.401(b) and 195.452(h).

The requirement for operators to patrol their pipelines regularly for signs of failures is longstanding (Sec. 195.412(a)). However, we recently broadened requirements by publishing standards on integrity management which will require pipelines in or near high-consequence areas, such as drinking water sources, to be internally inspected or pressure tested at regular intervals for corrosion, cracks, and other defects (65 FR 75377; Dec. 1, 2000). These new standards currently apply to operators with 500 or more miles of hazardous liquid pipelines, and we have proposed similar standards for the remaining hazardous liquid operators subject to part 195 (66 FR 15821; Mar. 21, 2001).

The following material, which is organized by sections of final subpart H, summarizes comments on the NPRM. In addition, the material explains how we treated the comments and other considerations in developing final subpart H. If a subsection is not mentioned, no significant comments were received on the corresponding proposed rule and we are adopting the proposed rule as final.

Section 195.551. This informational section provides the content of subpart H. Subpart H contains minimum requirements for protecting steel pipelines against corrosion.

In commenting on proposed Sec. 195.551, Tosco suggested we replace the term ``steel'' with ``metallic'' so subpart H would apply to pipelines made of any metal. Indeed, our corrosion control standards for gas pipelines apply to any metallic pipeline (49 CFR 192.451(a)). However, in contrast to gas pipelines, hazardous liquid and carbon dioxide pipelines are almost exclusively made of steel. For this reason, many of the existing standards in part 195, including corrosion control standards, apply only to steel pipelines. Our review of the corrosion control standards did not disclose a need to expand their coverage to include pipelines made of metals other than steel. In commenting on the NPRM, no one, including Tosco, presented information to explain why the coverage should be expanded. Nevertheless, operators are required to provide us an opportunity to review the safety of any pipeline that is to be constructed with a material other than steel (Sec. 195.8). In the case of a metallic pipeline made from a material other than steel, such as aluminum, our review would include the operator's plan for corrosion control.

Section 195.553. This new section was not in the NPRM. It provides definitions of terms used in subpart H. The definitions of ``active corrosion,'' ``electrical survey,'' and ``pipeline environment,'' proposed in Sec. 195.569(c), drew no adverse comment. Additionally, final Sec. 195.553 establishes definitions of ``buried'' and ``you.'' The definition of ``buried'' reflects the common corrosion control practice of treating any portion of pipe in contact with the soil as if that portion were buried. The term ``you'' has the same meaning as ``operator.''

Section 195.555. This section, based on proposed Sec. 195.553, keeps in effect the existing qualification standards in Sec. 195.403(c) for corrosion control supervisors. Under Sec. 195.403(c), each operator must require and verify that its supervisors maintain a thorough knowledge of that portion of the corrosion control procedures established under Sec. 195.402 for which they are responsible, to insure compliance.

While Tosco and WUTC supported the proposed rule, Phillips objected to it. Phillips believed that part 195 should include qualifications for supervisors of all operation and maintenance activities, not just corrosion control. In the negotiated rulemaking on qualification of pipeline personnel (64 FR 46866; Aug. 27, 1999), we removed the requirements in Sec. 195.403(c) concerning qualifications of supervisors of operations and maintenance activities, effective October 28, 2002. We did so based on the requirement under subpart G of part 195, that on this date, individuals performing regulated operation and maintenance activities must be fully qualified, thus lessening the need to regulate the qualifications of their supervisors. After revising Sec. 195.403(c), our more specific review of the corrosion control standards called attention to the special role that supervisors play in carrying out corrosion control activities. As we explained in the NPRM, individuals qualified to do such activities as taking electrical readings, usually hand the data collected over to supervisors who make critical decisions about corrosion control adequacy and the need for corrective action. None of the commenters, including Phillips, argued that corrosion control supervisors do not need to have the qualifications required by existing Sec. 195.403(c). So given the special role of corrosion control supervisors and the apparent acceptability of the existing supervisor qualification requirements, we continue to believe those requirements should remain in effect after October 28, 2002. This decision does not affect the expiration on October 28, 2002, of qualification requirements for supervisors of other operation and maintenance activities.

Equilon and NACE believed qualifications for supervisors should be no less rigorous than stated in paragraph 1.3 of NACE Standard RP0169-96. These NACE provisions address the need for corrosion control supervisors to have a minimum level of technical competency.\1\ In our corrosion control review, we considered this NACE provision as well as 49 CFR 192.453, which provides that gas pipeline corrosion control procedures must be carried out by or under the direction of a person qualified in corrosion control methods. Also, in the San Antonio meeting notice, we asked if more specific standards are needed for individuals who direct corrosion control procedures. Everybody who responded opposed changing Sec. 192.453, and most responders also opposed establishing specific technical qualifications like those in NACE Standard RP0169-96. We expect that individuals who qualify as a supervisor under proposed Sec. 195.553, will have appropriate technical training or experience in corrosion control. Given that neither our review, nor comments on the NPRM disclosed anything in the pipeline industry's safety record to demonstrate the need for more specific technical qualifications, we did not adopt the Equilon and NACE comment.

\1\ Paragraph 1.3 reads:

The provisions of this standard shall be applied under the direction of competent persons who, by reason of knowledge of the physical sciences and the principles of engineering and mathematics, required by education and related practical experience, are qualified to engage in the practice of corrosion control on buried or submerged metallic piping systems. Such persons may be registered professional engineers or persons recognized as corrosion specialists or cathodic protection specialists by NACE if their professional activities include suitable experience in external corrosion control of buried or submerged metallic piping systems.

Sections 195.557, 195.559, and 195.561. These three standards on

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external coating are based on proposed Sec. 195.555 and 195.557. Collectively, the standards require buried or submerged pipelines to have external coating with particular attributes, and require operators to inspect pipe coating and repair any damage. As stated in proposed Sec. 195.555, the standards are limited to pipelines constructed, relocated, replaced, or otherwise changed after certain effective dates in Sec. 195.401(c); and limited to certain converted pipelines. In final Sec. 195.557, we have clarified that aboveground breakout tank bottoms need not be coated. We determined that such a requirement is impractical and not a customary corrosion control practice.

In the NPRM, we proposed in Sec. 195.555 to limit the applicability of proposed Secs. 195.557 (external coating), 195.559 (cathodic protection), and 195.561 (test leads) to pipelines constructed, replaced, relocated, or otherwise changed after the applicable effective date. We based proposed Sec. 195.555, for the most part, on existing Sec. 195.200, titled Scope, which similarly limits the applicability of corresponding existing Secs. 195.238, 195.242, and 195.244. However, we inadvertently omitted from Sec. 195.555 the pipe movement exception included in Sec. 195.200. In this Final Rule, the substance of proposed Sec. 195.555 regarding external coating and cathodic protection is in Sec. 195.557(a), which does include the omitted exception for pipe movement. We addressed the proposed limit on test leads differently, as discussed below under the heading, section 195.567.

Tosco believes it would be helpful to include in subpart H the past effective dates cross-referenced in proposed Sec. 195.555. Tosco believes the dates are not widely known. We did not adopt this comment because the dates are already stated in Sec. 195.401(c) for purposes of indicating the applicability of standards in addition to corrosion control standards, and we do not want to create an unnecessary redundancy in part 195.

Final Sec. 195.557 specifies which pipelines must have external coating. Rather than cross-referencing Sec. 195.5(b) to indicate which converted pipelines must have coating, we transferred to final Sec. 195.557 the coating aspect of Sec. 195.5(b). We transferred the cathodic protection aspect to final Sec. 195.563(b); and the test lead aspect is covered by Sec. 195.567.

Equilon and NACE suggested we establish an additional standard to minimize damage to coating when operators install pipe by boring, driving, directional drilling, or any similar method. Final Sec. 195.559(d) requires external coating to have enough strength to resist damage due to handling and soil stress. We believe this standard is broad enough to cover the potential pipe installation problems raised by these commenters.

Phillips advised against requiring the installation of coating on older existing bare or ineffectively coated pipelines. We believe Phillips may be referencing existing hazardous liquid pipelines constructed before the applicable effective dates stated in Sec. 195.401(c). These pipelines are not subsequently replaced, relocated, or otherwise changed. Final Sec. 195.557 does not require these older pipelines to be coated.

Tosco suggested that Sec. 195.557 should include the dates for which pipelines must have external coating. The final rule accomplishes this objective by cross-referencing Sec. 195.401(c). Restating the dates listed in Sec. 195.401(c) would be unnecessarily redundant since the dates are in Sec. 195.401(c) for purposes other than corrosion control.

Section 195.563. Final Sec. 195.563 combines cathodic protection requirements proposed in Secs. 195.555, 195.559, and 195.563. It also cross-references final Sec. 195.573(b), which requires cathodic protection of unprotected pipe found to have active corrosion. As a result, all pipelines that must have cathodic protection under subpart H are identified in a single section.

Final Sec. 195.563(a), which is based on proposed Secs. 195.559(a) and (b), requires cathodic protection on each pipeline that must have an external coating under Sec. 195.557(a). The cross-reference to Sec. 195.557(a) limits the cathodic protection requirement to those pipelines constructed, relocated, replaced, or otherwise changed after certain dates, as proposed under Sec. 195.555. Section 195.563(a) does not contain the second sentence of proposed Sec. 195.559(a) which would require operators to have a test procedure to determine whether adequate cathodic protection was achieved. We now believe this sentence is redundant due to the routine monitoring conducted to determine the adequacy of cathodic protection, required by final Sec. 195.573(a). Also, amended Sec. 195.402(c)(3) requires operators to have procedures to carry out Sec. 195.573(a). Although proposed Sec. 195.559(b) only referred to completion of construction as the beginning of the period during which cathodic protection must be installed, final Sec. 195.563(a) reflects the broader applicability indicated by proposed Sec. 195.555.

We proposed in Sec. 195.559(a), which was based on existing Sec. 195.242(a), a requirement that operators install cathodic protection systems on all buried or submerged pipelines ``to mitigate corrosion that might result in structural failure.'' Equilon and NACE suggested this proposed rule would be clearer if we replaced ``structural failure'' with ``structural failure or penetration of pipe or tank wall.'' In light of their comment, we believe the phrase, ``to mitigate corrosion that might result in structural failure,'' creates confusion. It could be interpreted to require protection only against severe external corrosion. Moreover, since it is clear that existing Sec. 195.242(a) requires cathodic protection against all external corrosion, the phrase seems superfluous. Therefore, we did not use it in final Sec. 195.563(a).

Equilon and NACE also commented on the Sec. 195.559(b) proposed requirement that a cathodic protection system be installed not later than 1 year after completing construction. They believe cathodic protection should be in effective operation at the end of 1 year, to guard against significant corrosion that could be caused by stray currents or galvanic long-line currents. We believe effective operation is implicit in the existing and proposed standards on installation of cathodic protection. Nevertheless, to avoid confusion on this point, in final Sec. 195.563(a) we replaced ``installed'' with ``in operation.'' This change is consistent with the comparable standard for gas pipelines in Sec. 192.455(a)(2). Under final Sec. 195.571, when the cathodic protection system is placed in operation, it would have to comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs 6.2 and 6.3 of NACE Standard RP0169-96. Subsequent electrical tests and other steps required by final Sec. 195.573(a) will assure that adequate protection is maintained.

WUTC raised the concern that under proposed Sec. 195.559(b) corrosion could go uncontrolled on some facilities for up to 2 years. Based on a Washington State administrative rule, WUTC recommended that Sec. 195.559(b) require that facilities be cathodically protected within 90 days after they are buried or submerged. We did not propose to change the currently required time limit (1 year after completing construction) because our review of the corrosion control standards and the comments from the San Antonio meeting did not indicate any need to reduce the installation time limit. After considering

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WUTC's comment, we still believe 1 year after construction is acceptable as a generally applicable time limit considering that soil conditions may need time to stabilize in order to support cathodic protection.

Final Sec. 195.563(b) requires cathodic protection on certain converted pipelines. This requirement does not differ substantively from the cathodic protection aspect of the corrosion control requirement of Sec. 195.5(b). Therefore, we are modifying Sec. 195.5(b) to cross-reference the new subpart H standards.

Under final Sec. 195.563(c), which is based on proposed Sec. 195.563, all buried or submerged pipelines, that have an effective external coating must have cathodic protection. This requirement does not apply to breakout tanks. This requirement is substantially the same as existing Sec. 195.414(a), which requires that all effectively coated pipelines must be cathodically protected, except for breakout tank areas and buried pumping station piping.

However, Equilon and NACE each stated it saw no need to except buried piping in breakout tank areas and pumping stations from the requirement to cathodically protect effectively coated pipelines. We agree that the exception seems to lack a sound safety basis. For example, NACE Standard RP0169-96 does not have a similar exception from cathodic protection. Also, we believe it is now common practice in the hazardous liquid pipeline industry to cathodically protect effectively coated buried piping in breakout tank areas and pump stations. So, in view of the Equilon and NACE comments, and our further consideration, we decided to terminate the exception for buried piping in breakout tank areas and pumping stations. Therefore, the final rule keeps the exception in effect only until December 29, 2003. This period will give operators time to install cathodic protection on any effectively coated piping in breakout tank areas and pumping stations where it is not already installed. Also, since no one commented on application of the proposed rule to the bottoms of breakout tanks and there may not be many older breakout tanks that have effectively coated bottoms, the final rule does not change the present exception for breakout tank bottoms.

Initially, we did not propose regulations similar to Secs. 195.414(b) and (c), which require cathodic protection in areas of active corrosion found through electrical inspections previously required on bare pipelines, breakout tank areas, and buried pumping station piping. We reasoned that Secs. 195.414(b) and (c) are no longer necessary because the inspection deadlines had expired. However, we now recognize that the cathodic protection provisions of Secs. 195.414(b) and (c) are continuing requirements, and so we included them in subpart H as final Sec. 195.563(d).

Section 195.565. This section, concerning the installation of cathodic protection on breakout tanks, is the same as proposed Sec. 195.559(c). There were no comments on proposed Sec. 195.559(c).

Section 195.567. In this section concerning test leads, paragraphs (a) and (b) are based on proposed Sec. 195.561 and existing Sec. 195.244. The existing test lead standards in Sec. 195.244 apply to onshore pipelines constructed, replaced, relocated, or otherwise changed after certain past dates; and to onshore converted pipelines if required by Sec. 195.5(b). The NPRM did not propose to vary this application. However, upon further consideration of the importance of test leads in determining the adequacy of cathodic protection, we are applying final Sec. 195.567 to all onshore pipelines that must have cathodic protection under subpart H. This increased coverage will affect pipelines or segments of pipelines that must have cathodic protection under existing Secs. 195.414 and 195.416(d) (i.e., effectively coated pipelines and places on bare pipelines, breakout tank areas, and pumping station piping where active corrosion is found through electrical inspection). The increased coverage will also affect converted pipelines that were not substantially in compliance with existing Sec. 195.244 when placed in service, as Sec. 195.5(b) now permits. To ease the burden of compliance on existing cathodically protected pipelines or pipeline segments on which test leads are not now required by existing Sec. 195.244 or Sec. 195.5(b), final Sec. 195.567(a) allows operators 3 years to identify these pipelines or pipeline segments and install test leads as necessary to meet Sec. 195.567(b). On existing unprotected pipelines, any newly identified segment that must have cathodic protection as a result of an electrical survey under final Sec. 195.573(b), must have test leads in time to carry out the annual monitoring test under final Sec. 195.573(a).

Final Sec. 195.567 is consistent with acceptable practices. The practices recommended for test leads in NACE Standard RP0169-96 and in ASME B31.4 are not limited to new, relocated or replaced pipelines. Also, our gas pipeline regulations in 49 CFR 192.469 and 192.471 for test stations and test leads, apply to all gas pipelines that must be cathodically protected under 49 CFR part 192. Moreover, existing Sec. 195.416(a) requires annual testing of each cathodically protected pipeline to determine the adequacy of cathodic protection; and operators normally comply with this requirement by obtaining electrical measurements through test leads. So we believe Sec. 195.567 will have only a minimal impact on hazardous liquid pipeline companies.

Based on existing Sec. 195.244(b)(1), we proposed in Sec. 195.561(b)(1) that operators install test leads with enough looping or slack to prevent the leads from being unduly stressed or broken during backfilling. Equilon and NACE suggested that to assure test lead wires remain effective, we should add the phrase ``to remain mechanically secure and electrically conductive.'' We believe the objective of this phrase is within the purpose of the existing rule, and therefore, added the phrase to final Sec. 195.567(b)(2) for emphasis.

The long term integrity of test leads is also covered by final Sec. 195.567(c). Based on proposed Sec. 195.573, this standard requires maintenance of test leads. There were no comments on the proposed rule, however we edited the final rule for clarity.

Equilon and NACE also commented on testing cathodic protection of offshore pipelines. They contended that test lead readings at platforms or at shore locations may be of little benefit in determining the adequacy of cathodic protection of offshore pipelines. As an alternative to such readings, they suggested we require operators to analyze or inspect each cathodic protection system before the end of its design life. In our experience, test leads for offshore pipelines normally are installed only on platforms or on shore because of the difficulty of accessing leads at underwater locations. For this reason, Sec. 195.567 does not apply to buried or submerged portions of offshore pipelines. Since pipeline corrosion in an offshore environment generally occurs at a uniform rate, we believe readings taken by operators at offshore platforms or on shore are used satisfactorily to determine the adequacy of protection over the entire pipeline. Moreover, this test method is acceptable for offshore gas pipelines under paragraph A862.15 of the ASME B31.8 Code. Because there is no information to support the need to require the use of an alternative testing method, we chose not to take action on the commenters' suggestion.

WUTC commented that because the proposed standard does not prescribe the number or precise location of test leads, government inspectors may disagree with operators over whether

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test readings are sufficient to determine the adequacy of cathodic protection. To ameliorate this situation, WUTC suggested that we require operators to conduct close-interval electrical surveys every 5 years. Although final Sec. 195.567 does not specify the number or precise location of test leads, it does provide a performance standard for the location of test leads. Under Sec. 195.567(b)(1) test leads must be installed at sufficiently frequent intervals to obtain electrical measurements indicating the adequacy of cathodic protection. Section 4.5 of NACE Standard RP0169-96, which lists many customary test lead locations, may be used as a guide to comply with Sec. 195.567(b)(1). Additionally, the final rule on monitoring external corrosion control, Sec. 195.573, will require operators to use close-interval surveys in some situations and install additional test leads where warranted.

Section 195.569. This section, which is based on proposed Sec. 195.565, provides that whenever an operator learns that any portion of a buried pipeline is exposed, the exposed portion must be examined for external corrosion if the pipe is bare or has deteriorated coating. Further, if external corrosion requiring remedial action is found, the operator must investigate pipe in the vicinity of the exposed portion (by visual examination, indirect method, or both) to determine if there is any additional external corrosion requiring remedial action.

Phillips requested more flexibility in the proposed requirement to look for additional corrosion. Phillips commented that the extent of further investigation should depend on the type of corrosion found and whether the corrosion could be expected to extend beyond the exposed segment. We do not believe there is a clear understanding of the relationship between the type of corrosion and the likelihood of finding similar corrosion in the vicinity of the exposed pipe to justify limits on the requirement for additional investigation. Pipe and soil conditions are generally too variable to make such predictions with accuracy. Therefore, we did not adopt Phillips' comment.

WUTC believed subpart H should include additional requirements for operators to do more to determine the condition of coating than just visually examine it whenever pipelines are exposed. WUTC stated that the standards should require operators to conduct surveys to identify areas with coating defects and take remedial measures such as re-coating the pipeline. Although the final rules do not specifically require pipe coating surveys, operators must conduct electrical tests periodically to determine the adequacy of corrosion control on their buried pipelines. Low cathodic protection potential readings obtained during these tests often are a sign of coating defects. So, in areas with low potential readings, many operators supplement cathodic protection tests with coating surveys to help them identify places where the pipeline must be excavated to look for corrosion cells or to determine where additional cathodic protection must be applied. The need to mandate the use of coating surveys in addition to electrical tests for corrosion, was not evident from our review of the regulations.

Section 195.571. This standard, proposed as Sec. 195.567, incorporates by reference the criteria and other considerations in section 6 of NACE Standard RP0169-96, as standards for the adequacy of cathodic protection.

Environmental Defense and Iowa argued that because cathodic protection criteria are fundamental to safety, the criteria should be stated in part 195 rather than incorporated by reference. Iowa believed that acquiring and maintaining a separate document is arbitrary and unnecessarily burdensome. In considering these comments, we reviewed OMB Circular A119 and the National Technology Transfer and Advancement Act of 1995. Both documents direct Federal agencies to use consensus standards where practical to meet their policy objectives rather than develop government-unique standards. We also reviewed the rules of the Federal Register on incorporation by reference. In light of these Federal policies, we think it is appropriate for us to incorporate the NACE criteria and other considerations by reference, as proposed.

Enron, Environmental Defense, and L. A. (Roy) Bash urged us to adopt the criteria in Appendix D of part 192 instead of the NACE criteria. Enron commented that many operators are successfully using Appendix D for hazardous liquid pipelines; and Environmental Defense viewed Appendix D as more specific and therefore more enforceable. Roy Bash submitted technical documentation in support of two Appendix D criteria, 300 mV shift and E-log-I. In the NPRM we discussed our reluctance to propose Appendix D as the new standard for hazardous liquid pipelines because the Appendix D 300 mV shift and E-log-I criteria are not incorporated in the NACE Standard. Furthermore, we explained that under paragraph 6.2.1 of the NACE Standard, operators may use any criteria which they can demonstrate achieves corrosion control comparable to section 6 criteria. Also, operators may continue to use criteria which they have successfully applied to existing pipelines, on these pipelines. While this provision may satisfy Enron, and should satisfy Roy Bash's concern about the continued use of the 300 mV shift and E-log-I criteria, the lack of specificity in paragraph 6.2.1 may be indicative of Environmental Defense's concern. Yet, we do not believe the performance wording of paragraph 6.2.1 alone is sufficient reason not to reference section 6 of the NACE Standard. On the contrary, we generally favor performance standards over specification standards because they encourage operators to develop and apply better alternatives. If however, an operator chooses to use alternative criteria, we will carefully examine the operator's rationale for determination that the criteria met the ``comparable to'' or ``successfully applied'' tests of paragraph 6.2.1 of the NACE Standard.

WUTC was concerned that the criteria in section 6 of the NACE Standard would not be mandatory because paragraph 6.1.1 refers to paragraph 1.2, which states that the Standard is a guide; and also refers to paragraph 1.4, which allows deviations from the Standard. Proposed Sec. 195.567 refers solely to the criteria and other consideration provisions of section 6, which are contained in paragraphs 6.2 and 6.3 of the NACE Standard. We did not intend to allow operators to treat section 6 as a guide or to deviate from the criteria and other considerations in section 6. Therefore, the final rule refers to paragraphs 6.2 and 6.3, instead of section 6.

WUTC was also concerned about special conditions, such as elevated temperatures, disbonded coatings, thermal insulating coatings, shielding, bacterial attack, and unusual contaminants in the electrolyte, which may cause cathodic protection to be ineffective.

WUTC believed the rules on coating and cathodic protection should address these special conditions. The theory behind final Sec. 195.571 is that if all external surfaces of a pipeline are cathodically protected according to the criteria and other considerations in paragraphs 6.2 and 6.3 of the NACE Standard, external corrosion will be controlled successfully. In practice, if an operator learns though in-line inspection or other means that because of a special condition external corrosion is not being controlled successfully, the operator must take corrective action. The operator could either remedy the condition or adjust the cathodic protection system to assure the adequacy of cathodic protection in the

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area of the special condition. We believe this requirement is implicit in final Sec. 195.571. Section 195.573(e) also would require corrective action if the condition is detected by monitoring under Sec. 195.573.

In addition, WUTC was concerned that the proposed rules did not specify how long the cathodic protection current may be shut off when measuring polarization decay under the minimum 100 mV criterion. WUTC suggested that the limit be no more than 48 hours, unless a recording chart shows continuing significant decay beyond that time. To satisfy the100 mV criterion by the decay method, operators must determine that a negative polarization voltage shift of at least 100 mV occurs after the immediate voltage shift caused by shutting off the cathodic protection current. Whether this minimum negative voltage shift occurs in minutes or hours after the current is cut off, it is irrelevant to satisfying the criterion. We recognize that the longer the current remains off, the greater the opportunity for the pipeline to corrode. However, in our experience decay tests have not posed a serious problem in this regard to warrant establishing a time limit.

Finally, WUTC opposed use of the net protective current criterion on bare or ineffectively coated hazardous liquid pipelines. WUTC was concerned about the criterion being applied only at predetermined current discharge points identified through leaks, leak history, or electrical surveys, preventing the pipeline from having complete cathodic protection against corrosion leaks. WUTC suggested that if we allow use of the criterion, we limit its use to pipelines constructed before part 195 went into effect. According to part 195's terms, the net protective current criterion applies only to bare or ineffectively coated pipelines. Because all pipelines subject to part 195 construction standards must be effectively coated, the net protective current criterion will mostly be used on older pipelines constructed before those standards took effect. The effective dates for different groups of pipelines are stated in Sec. 195.401(c).

WUTC's primary concern seems to be that we did not propose a requirement that operators fully cathodically protect bare or ineffectively coated pipelines. We did not propose such action for several practical reasons. To cathodically protect these pipelines over their entire surface area without first coating or recoating them would require very high levels of impressed currents. Cathodic protection systems producing such high current levels would be costly to install, maintain, and operate. Also, to coat all bare or ineffectively coated buried pipelines in order to facilitate cathodic protection could be a costly endeavor. We also considered the possibility that raising pipe sections to coat them would likely create unanticipated stresses and disturb pipe foundations, introducing new risk factors not present in the existing pipelines.

Section 195.573. This section is based on proposed Sec. 195.569. It requires operators to monitor the performance of cathodic protection facilities and monitor unprotected pipe for active corrosion.

Final Sec. 195.573(a) enhances proposed Sec. 195.569 with regard to determinations of the adequacy of cathodic protection. We edited Sec. 195.573(a) to clearly state that operators must conduct tests to determine whether cathodic protection complies with Sec. 195.571 and not whether cathodic protection is adequate, as proposed. In addition, we are concerned that proposed Sec. 195.569 does not provide latitude in monitoring separately protected short segments of bare or ineffectively coated pipelines, as does the corresponding rule for monitoring protected gas pipelines (49 CFR 192.465(a)). The gas rule allows monitoring of short protected segments over a 10-year period where annual monitoring is impractical. We considered adding a similar provision to Sec. 195.573(a) but decided that the 10-year period would add more latitude than circumstances warrant on bare or ineffectively coated hazardous liquid pipelines. Many operators now monitor short protected segments of bare or ineffectively coated lines on the same cycle as adjoining unprotected segments. So, rather than use the gas rule provision, we added a provision that allows monitoring at 3-year intervals which is consistent with the monitoring cycle we are adopting for unprotected sections (see discussion of Sec. 195.573(b) below).

We also addressed the problem of how to test pipelines to determine the adequacy of cathodic protection. In complying with existing Sec. 195.416(a), which was the basis of proposed Sec. 195.569, operators generally conducted electrical surveys. This action involves measuring potentials at pre-established test stations, to determine the adequacy of cathodic protection. In practice, however, this method of compliance has not always been sufficient to assure protection of all pipeline surfaces. Corrosion problems often arise in areas between test stations where there may be interference currents, different environmental conditions, damaged coatings, or malfunctioning anodes. So, in order to check on cathodic protection adequacy in greater detail, many operators augment test station data with periodic close-interval electrical surveys or use newer technologies. As WUTC pointed out in its comments, these more detailed surveys also help operators determine if additional test stations are needed to assure the adequacy of cathodic protection.

Paragraph 10.1.1.3 of NACE Standard RP0169-96 recommends that operators use close-interval surveys where they are practicable and sound engineering judgment indicates they are necessary.\2\ For this reason and because we believe the general method of monitoring cathodic protection at established test stations may not always be sufficient, we have referenced the NACE provision in final Sec. 195.573(a)(2). Although the final rule does not prescribe a frequency of close-interval surveys, operators will have to describe in their maintenance procedures the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of the NACE Standard, and then follow those procedures.

\2\ Paragraph 10.1.1.3 reads: Where practicable and determined necessary by sound engineering practice, a detailed (close-interval) potential survey should be conducted to (a) assess the effectiveness of the cathodic protection system; (b) provide base line operating data; (c) locate areas of inadequate protection levels; (d) identify locations likely to be adversely affected by construction, stray currents, or other unusual environmental conditions; or (e) select areas to be monitored periodically.

In order to provide operators with time to prepare for compliance with the new close-interval survey requirement, the compliance date for existing pipelines will not be mandatory until December 29, 2003.

Final Sec. 195.573(b), which is based on proposed Sec. 195.569(c), requires that operators must reevaluate their unprotected pipe and cathodically protect the pipe where active corrosion is found. Operators must determine if active corrosion exists by electrical survey where practical, or otherwise by a review and analysis of certain maintenance records and the pipeline environment. Proposed definitions of the terms ``active corrosion,'' ``electrical survey,'' and ``pipeline environment'' are combined with other definitions in final Sec. 195.553. Also, final Sec. 195.573(b) applies to ``pipe'' rather than ``pipelines'' as proposed, because we did not intend for the proposed rule to apply to unprotected breakout tank bottoms. Integrity inspection of the bottoms of breakout tanks is covered by existing Sec. 195.432.

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Equilon, Environmental Defense, and NACE argued that because unprotected pipelines may deteriorate as they age, operators should reevaluate these pipelines at intervals of less than 5 years, the maximum interval proposed in the NPRM. They suggested that to be consistent with part 192 we set the maximum interval at 3 years, not to exceed 39 months. Like these commenters, Iowa also saw a need to add 3 months to the maximum interval, whether it be 5 or 3 years, to provide scheduling and operational flexibility.

In view of the three comments favoring a 3-year inspection interval and the Technical Hazardous Liquid Pipeline Safety Standards Committee's unanimous recommendation to establish a maximum 3-year interval (see the Advisory Committee Consideration heading below), we reconsidered whether the appropriate maximum inspection interval should be 3 or 5 years. We considered the fact that the relation between relevant risk factors on unprotected pipelines and an appropriate inspection interval is uncertain. As discussed in the NPRM, we are also seeking to make the corrosion control standards for gas and hazardous liquid pipelines consistent wherever reasonable. At present part 192 prescribes a maximum inspection interval of 3 years for unprotected gas pipelines; and part 195 prescribes 5 years. Although there is no evidence in the record to demonstrate conclusively the advantage of a 3-year interval over a 5-year interval, taking into consideration the risk to the public and environment, we believe the more conservative 3-year interval is the prudent choice. Furthermore, we believe this choice is reasonable based on our enforcement experience, as well as, discussions with industry representatives which indicate that many hazardous liquid pipeline operators inspect their unprotected pipelines every 3 years. Therefore, the final rule is changed from the proposed maximum 5-year interval to a maximum 3-year interval.

In order to provide operators with time to prepare for compliance with the new 3-year inspection interval, compliance will not be mandatory until December 29, 2003.

Equilon and NACE suggested that in-line inspection may be a more appropriate alternative to electrical survey than analysis of leak repairs and other matters as proposed in Sec. 195.569(c). However, the proposed rule did not limit an operator's choice of alternatives to an analysis of leak repairs. Rather, where electrical surveys are impractical, we proposed the use of any alternative means of determining whether active corrosion exists, as long as that means includes a review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment. Under the final rule, if operators have in-line inspection data and want to use it as an alternative to electrical surveys where such surveys are impractical, they may do so provided they interpret the data in light of the required review and analysis of other pertinent information.

WUTC suggested we put the following sentence in the final rule: ``Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.'' We discussed in the NPRM why we did not propose such a requirement. We stated that it is unnecessary to direct such action due to the existing requirements under Sec. 195.401(b). This section requires operators to correct within a reasonable time any condition that could adversely affect safe operation of a pipeline system; and if an immediate hazard exists, to cease operating the affected part of the system until the condition is corrected. In addition, on pipelines that could affect high consequence areas, new Sec. 195.452(h) requires operators to take prompt actions to address integrity issues and to repair certain conditions within specific time limits. However, in light of WUTC's comment, we established Sec. 195.573(e) to draw attention to the remedial action required by existing Secs. 195.401(b) and 195.452(h).

WUTC also was concerned that the discretion built into the proposed definition of ``active corrosion'' would allow operators to ignore corrosion leaks detrimental to public safety or the environment. WUTC suggested we require operators to classify and schedule all corrosion leaks for repair. In response, we believe the purpose of proposed Sec. 195.569(c) is to require operators to look for and cathodically protect certain areas of corrosion before leaks occur. Operator response to leaks, whether due to corrosion or other causes, is not covered by new subpart H. Leak response is governed by existing Sec. 195.401(b) or Sec. 195.452(h), which together require timely corrective action for all unsafe conditions on pipelines subject to Part 195.

Section 195.575. This standard requires electrical isolation to provide for adequate cathodic protection. The standard is based on proposed Sec. 195.571.

Enron expressed support for the proposed rule; however, Tosco believed we should specify the frequency of inspection and electrical tests.

We did not adopt Tosco's comment because the purpose of the proposed inspection and electrical tests is to ensure that electrical isolation is adequate when it is installed. All post-installation inspections and tests of cathodic protection facilities are covered by final Sec. 195.573.

In final paragraph (d), for clarity, we changed the proposed wording ``where a combustible atmosphere is anticipated'' to read ``where a combustible atmosphere is reasonable to foresee.'' Similarly in paragraph (e), we changed the proposed ``where fault currents or unusual risk of lightning may be anticipated'' to read ``where it is reasonable to foresee fault currents or an unusual risk of lightning."

Section 195.577. The purpose of this standard, which is based on proposed Sec. 195.575, is to minimize the adverse effects of stray currents on pipelines and the effects of impressed currents on adjacent structures. Expressing support for the proposed rule, Tosco stated that the proposed program to identify, test for, and minimize the detrimental effects of stray currents may result in operators participating in corrosion coordinating groups. We agree that such coordination may be necessary for an effective program.

Section 195.579. This standard, proposed as Sec. 195.577, requires operators to investigate the effects of transporting hazardous liquid or carbon dioxide which could corrode the pipeline, and take adequate steps to mitigate corrosion. Tosco suggested that in the final rule we clarify that the investigation may be done by review of operating history. A review of relevant operating history may be a satisfactory investigation in some situations. However, we did not explicitly include this option in final Sec. 195.579. We used the proposed wording because we think it is broad enough to permit operators to use any method of investigation that will provide a sound basis for deciding how to mitigate internal corrosion adequately.

Under proposed Sec. 195.577(d), if operators discover harmful corrosion inside removed pipe, they must investigate further to determine if additional harmful corrosion exists in the vicinity of the removed pipe. Phillips suggested that the extent of further investigation should depend upon the type of corrosion found and whether that corrosion could be expected to extend beyond the exposed segment. We do not believe there is a clear understanding of the relationship between the type of corrosion and the

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likelihood of finding similar corrosion in the vicinity of removed pipe to justify limits on a requirement for additional investigation. The effect of corrosive liquids on pipe may be too variable to make such predictions with accuracy. Therefore, we did not adopt Phillips' comment.

Section 195.581. This section, based on proposed Sec. 195.579, modifies an existing requirement (Sec. 195.416(i)) that all pipelines exposed to the atmosphere must be protected against atmospheric corrosion by a suitable coating. Final Sec. 195.581 gives operators flexibility when deciding to coat pipelines where atmospheric corrosion will be limited to a light surface oxide, or will not affect the safe operation of the pipeline before the next scheduled inspection. Splash zones of offshore pipelines and soil-to-air interfaces of onshore pipelines are omitted from this exception.

Iowa opposed allowing pipe with metal loss to remain unprotected or unrepaired. Iowa stated that public safety should not depend on an operator's judgment of whether a corroding pipe will not fail before the next inspection (which could be up to 3 years). Yet under the proposed rule, if an operator chose not to coat, it would have to show that testing, investigation, or experience supports the decision. In other words, safety would not depend solely on an operator's judgment. Also, the need for coating would be reviewed again in 3 years. A 3-year delay in coating a pipeline judged to be safe should not jeopardize public safety, considering that atmospheric corrosion generally progresses at a slow rate. Therefore, we did not adopt Iowa's comment. Nevertheless, mindful of Iowa's concern, we edited the final wording to clarify that any decision not to coat a particular pipeline must be supported by testing, investigation, or experience relevant to that pipeline.

Tosco called the proposed rule ``a positive revision.'' However, Enron recommended that we add ``active'' as a descriptor of ``atmospheric corrosion.'' It believed the term ``active atmospheric corrosion'' would clarify that the rule does not apply to harmless corrosion. We did not adopt Enron's comment because we think the proposed exceptions will satisfy Enron's objective. Also, ``active atmospheric corrosion'' is a term that may not be in general use in the industry.

Section 195.583. Under this section, proposed as Sec. 195.581, operators must periodically inspect exposed pipelines for atmospheric corrosion, giving particular attention to areas such as soil-to-air interfaces. Onshore pipelines must be inspected every 3 years; and offshore pipelines every year. If any inspection reveals atmospheric corrosion, the operator must protect the pipeline against atmospheric corrosion in accordance with Sec. 195.581.

Enron, Equilon, Iowa, and NACE advocated adding a 3 months grace period to the maximum 3-year inspection interval. We agree that this period is useful to allow operators scheduling and operational flexibility, and included it in final Sec. 195.583.

Tosco wanted to make certain that the proposed remedial action would not be required for light surface oxide. By the cross reference to Sec. 195.581, final Sec. 195.583 allows operators latitude when deciding to coat pipelines which exhibit only a light surface oxide.

AEC urged us to allow operators to use means of assessment other than periodic visual inspection. As an example, AEC commented that by using in-line inspection and a corrosion growth model, operators could predict when a pipeline should be reinspected or repaired. This approach, according to AEC, would enable operators to allocate resources for maximum benefits instead of periodically scattering them across entire systems. AEC's comment indicates two things: first, AEC apparently misunderstood the proposed rule to mandate visual inspection; and second, AEC would like operators themselves to decide appropriate inspection frequencies with the aid of a corrosion growth model. As to the first item, the proposed rule would not limit operators to using visual means of inspection. They could use any means capable of detecting atmospheric corrosion, including in-line inspection devices. As to growth models, AEC did not suggest which model, if any, can successfully predict the growth of atmospheric corrosion on exposed pipelines in changing and varied environments. Furthermore, AEC did not suggest how operators would decide when to inspect exposed pipe that has no history of corrosion. Since the record of this rulemaking proceeding lacks information on these important issues, we have adopted the proposed inspection frequencies as final. However, we would welcome receiving more complete information that could possibly serve as a basis for changing the rule as AEC suggests.

AEC also suggested we extend the proposed maximum inspection interval for onshore pipelines from 3 years to 5 years. It believes that extending the time to 5 years is appropriate because atmospheric corrosion rates are low, and exposed pipe is typically located outside high consequence areas where the maximum interval for reevaluation of pipeline integrity is 5 years (see Sec. 195.452(j)(3)). In developing the proposed rule, we considered whether 3 or 5 years would be the appropriate maximum interval. We proposed 3 years primarily because the ASME B31.4 Code, a widely accepted consensus standards code for hazardous liquid pipelines, specifies a minimum 3-year inspection frequency for atmospheric corrosion onshore. Generally, atmospheric corrosion rates are found to be low and therefore, we must assume this factor was considered when the 3-year consensus standard was adopted. However, a low rate by itself does not seem to justify a longer interval. Also, the 5-year interval for integrity reevaluation in high consequence areas is based on various factors besides corrosion rate, including the time needed to carry out in-line inspections or pressure testing on the pipelines involved. Moreover, the 5-year reevaluation applies in addition to other monitoring frequencies required by part 195, such as annual cathodic protection monitoring and biweekly right-of-way inspections. Yet, we did not intend the 5-year period to serve as a yardstick for determining the adequacy of other monitoring frequencies.

Finally, AEC was concerned about the possible adverse consequences of visually inspecting soil-to-air interfaces on pipe spans over creeks and ravines. AEC suggested that if the interface is on a steep bank, the process of visually examining the pipe could accelerate bank erosion causing water pollution and overstress of the pipeline. We believe the proposed inspection requirement is flexible enough to allow operators to take precautions in inspecting soil-to-air interfaces on steep banks to avoid or minimize the disturbance AEC foresees. Should a disturbance occur that affects the safe operation of the pipeline, the operator would have to correct the problem. We did not change the final rule as a result of this comment.

Section 195.585. This section, which is substantively the same as proposed Sec. 195.583, requires operators to take certain actions to correct corroded pipe. If general corrosion reduces pipe wall thickness to less than that required for the maximum operating pressure of the pipeline or if localized corrosion pitting exists to a degree that leakage might result, the operator must: replace the pipe; repair the pipe; or reduce the maximum operating pressure commensurate with the strength of the pipe. We edited the final rule to clarify that it is the ``maximum operating pressure'' that must be reduced.

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Environmental Defense believed this section also should require operators to account for why corrosion has become so advanced. This commenter suggested operators should review their corrosion control systems to ensure that further harmful corrosion will not occur. We believe the combination of cathodic protection criteria under Sec. 195.571 and periodic monitoring under Sec. 195.573 will accomplish the objective of this comment. Whenever an operator discovers a corrosion control deficiency, it must review its corrosion control system and make adjustments as necessary to provide adequate protection against corrosion. If adequate protection cannot be achieved, the pipe involved may have to be replaced.

Section 195.587. This section is based on proposed Sec. 195.585. It authorizes, but does not require, operators to use the widely accepted ASME B31G criteria for determining the remaining strength of corroded steel pipe.

Iowa fully supported the proposed rule. In contrast, WUTC was concerned that because ASME B31G allows wall loss of up to 80 percent without repair or replacement, it does not provide a reasonable measure of strength needed to withstand cyclical stresses, environmental loads, and other combined forces.

Although WUTC is correct, we consider B31G to be a guide to the capability of corroded pipe to withstand internal pressure. Final Sec. 195.587 advises operators that B31G sets limits on use of the criteria. One limitation states that a pipe subject to significant secondary stresses should not be kept in service for the purpose of satisfying the criteria (paragraph 1.2(d)). To ensure that operators consider the effects of secondary stresses, in final Sec. 195.585(a)(1), we added the words ``needed for serviceability'' immediately following ``strength of the pipe.'' Consequently, as a remedy for generally corroded pipe, operators may reduce maximum pressure commensurate with the pipe strength needed for serviceability. In determining the amount of pressure reduction required, operators may use B31G but also must consider any significant secondary stresses that may affect pipe serviceability.

Section 195.589. Under this section, proposed as Sec. 195.587, operators must to keep current records or maps of the location of cathodically protected pipelines; cathodic protection facilities (including anodes) installed after the Final Rule takes effect; and structures bonded to cathodic protection systems. Additionally, operators must keep records of required maintenance activities including inspections, tests, analyses, checks, demonstrations, examinations, investigations, reviews, and surveys. These records must demonstrate the adequacy of corrosion control measures, or that corrosion requiring control measures does not exist. Operators will have to keep these records for at least 5 years, except that records related to Sec. 195.569 (examination of pipeline when exposed); Secs. 195.573(a) and (c) (monitoring external corrosion control); and Secs. 195.579(b)(3) and (c) (monitoring internal corrosion control) will have to be kept for as long as the pipeline involved is in service.

Commenting on examinations of exposed pipe, Equilon and NACE believed that there is no need to keep records of good pipe for as long as the pipeline remains in service, and that there is no need to keep records of defective pipe after the latest in-line inspection. Equilon and NACE also contended that old records of internal corrosion monitoring are of little benefit without knowledge of flow rates, upstream pipeline operations, fluid properties, and other information. None of these records are generally available. We did not adopt either comment because the proposed records provide a useful history of pipeline condition and are easy to maintain in electronic form. The records may be helpful in assessing corrosion control needs, and could be used as a comparative base for evaluating in-line inspection data.

We also considered the Equilon and NACE comment that subpart H should not require operators to keep records of maintenance activities that occur before subpart H takes effect. Final Sec. 195.589 specifically states that records must be kept for certain maintenance activities ``required by this subpart.'' For example, final Sec. 195.589 does not require operators to keep records of corrosion control monitoring conducted before subpart H takes effect. However, until subpart H takes effect, Sec. 195.404(c)(3) requires records of corrosion control inspections and tests required by subpart F of part 195. Operators must continue to maintain records established under that section for the retention period prescribed.

Tosco believed we should revise Sec. 195.404(c)(3) to indicate that corrosion control records are required by subpart H. However, no confusion about the application of Sec. 195.404(c)(3) to corrosion control should occur because this section applies only to inspections and tests ``required by this subpart,'' meaning, required by subpart F. After new subpart H goes into effect, Subpart F will no longer require corrosion control inspections and tests.

Phillips argued that the current 2-year retention requirement in Sec. 195.404(c)(3) is adequate for auditing compliance, since 2 years of records show the current state of corrosion control. However, as we explained in the NPRM, 5 years is the minimum retention period that will assure the availability of records for our compliance auditing.

Environmental Defense stated that it would help government inspectors determine the adequacy of cathodic protection systems if we required operators to keep records of the location of existing cathodic protection facilities and not just those facilities installed after subpart H takes effect. While this suggestion has merit, we did not propose to require records of existing facilities due to the difficulty of creating such records, particularly for galvanic anode systems. Also, in our experience the lack of such a requirement has not caused a significant problem due to the number of operators who keep records of the location of existing corrosion control facilities.

Format and Organization

In accordance with Federal Register guidelines, we drafted final subpart H in an easier to read and understand format. Section headings are in the form of questions. We minimized passive voice and used the word ``you'' as a substitute for ``operator.'' Also, a few proposed sections were eliminated, combined with other sections, or separated into two or more sections. This Final Rule also changes Secs. 195.5, 195.402, 195.404 and removes Secs. 195.236, 195.238, 195.242, 195.244, 195.414, 195.416, 195.418 to account for the new subpart H.

Advisory Committee Consideration

We presented the NPRM for consideration by the Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC) at a meeting in Washington, DC on February 7, 2001 (66 FR 132; Jan. 2, 2001). The THLPSSC is RSPA's statutory advisory committee for hazardous liquid pipeline safety. The committee has 15 members, representing industry, government, and the public. Each member is qualified to consider the technical feasibility, reasonableness, cost-effectiveness, and practicability of proposed pipeline safety standards. The committee voted unanimously to approve proposed subpart H but unanimously recommended that we require operators of bare or ineffectively coated pipe to inspect the pipe for external corrosion every 3 years. Our treatment of this

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recommendation is discussed in the Discussion of Comments section under section 195.573. A transcript of the February 7, 2001, meeting is available in Docket No. RSPA-98-4470.

Regulatory Analyses and Notices

Executive Order 12866 and DOT Policies and Procedures. RSPA does not consider this rulemaking to be a significant regulatory action under section 3(f) of Executive Order 12866 (58 FR 51735; Oct. 4, 1993). Therefore, the Office of Management and Budget (OMB) has not received a copy of this rulemaking to review. RSPA also does not consider this rulemaking to be significant under DOT regulatory policies and procedures (44 FR 11034: February 26, 1979).

We prepared a Final Regulatory Evaluation of the final rules and a copy is in the docket. The evaluation states that the rules are, on the whole, comparable either to existing safety standards currently in part 195 for hazardous liquid pipelines or to existing safety standards in part 192 for gas pipelines. The evaluation also states that the information presented at public meetings and meetings with industry and state representatives strongly suggests that imposing gas pipeline safety standards for corrosion control on hazardous liquid pipelines would not require a significant departure from customary safety practices on liquid pipelines.

An important feature of the final rules not found in part 192 or part 195 is the reference to cathodic protection criteria in NACE Standard RP0169-96. The evaluation states that these criteria are well known and widely followed throughout the industry, as indicated by meetings with industry representatives and by the voluntary standards in the ASME B31.4 Code. The evaluation further states that operators who do not now apply the NACE criteria are likely to apply the criteria in appendix D of part 192. The final rules would allow use of appendix D criteria under conditions stated in the NACE Standard. The evaluation concludes that there should be only minimal additional cost, if any, for operators to comply with the final rules.

Final Sec. 195.563(c) (protecting effectively coated pipelines), Sec. 195.567 (test leads), and Sec. 195.573(a)(2) (monitoring cathodic protection by close-interval surveys or comparable technology) are changed from the proposed rules. However, the changes are consistent with industry practices and should not result in more than minimal additional costs.

Regulatory Flexibility Act. The final rules are consistent with customary practices for corrosion control in the hazardous liquid and carbon dioxide pipeline industry. Therefore, based on the facts available about the anticipated impacts of this rulemaking, I certify, pursuant to section 605 of the Regulatory Flexibility Act (5 U.S.C. 605), that this rulemaking will not have a significant impact on a substantial number of small entities.

Executive Order 13084. The final rules have been analyzed in accordance with the principles and criteria contained in Executive Order 13084, ``Consultation and Coordination with Indian Tribal Governments.'' Because the rules will not significantly or uniquely affect the communities of the Indian tribal governments and will not impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13084 do not apply.

Paperwork Reduction Act. Section 195.589 contains minor additional information collection requirements. Operators will be required to record the location of certain newly installed protection facilities, and keep these records for as long as the pipeline concerned is in service. In addition, records of inspections, tests, and other maintenance actions will have to be kept for as long as the pipeline is in service or for 5 years, depending on the nature of the information recorded. The present minimum retention period for records of inspections and tests is 2 years or the prescribed interval of test or inspection, whichever is longer (up to 5 years in some cases).

Hazardous liquid pipeline operators are required to keep records under Information Collection 2137-0047, Transportation of Hazardous Liquids by Pipeline: Record Keeping and Reporting Requirements.

Operators already maintain records of the location of their protection facilities for as long as the pipeline is in service. They do so to find the facilities for their own purposes and to carry out existing monitoring requirements in part 195. Also, we believe the burden of retaining inspection, test, and survey records for the longer period will be minimal. These records are largely computerized and maintaining these records in a computer file represents very minimal costs. Because the additional paperwork burdens of this final rule are likely to be minimal, we believe that submitting an analysis of the burdens to OMB under the Paperwork Reduction Act is unnecessary.

Unfunded Mandates Reform Act of 1995. This rulemaking will not impose unfunded mandates under the Unfunded Mandates Reform Act of 1995. It will not result in costs of $100 million or more to either State, local, or tribal governments, in the aggregate, or to the private sector, and is the least burdensome alternative that achieves the objective of the rule.

National Environmental Policy Act. We have analyzed the final rules for purposes of the National Environmental Policy Act (42 U.S.C. 4321 et seq.). Because the rules parallel present requirements or practices, we have determined they will not significantly affect the quality of the human environment. An environmental assessment document is available for review in the docket. We also made a finding of no significant impact.

Impact on Business Processes and Computer Systems. We do not want to impose new requirements that mandate business process changes when the resources necessary to implement those requirements could otherwise be applied to ``Y2K'' or related computer problems. The final rules do not mandate business process changes or require modifications to computer systems. Because the rules do not affect the ability of organizations to respond to those problems, we have not delayed the effectiveness of the requirements.

Executive Order 13132. The final rules have been analyzed in accordance with the principles and criteria contained in Executive Order 13132 (``Federalism''). The final rules do not contain any regulation that (1) has substantial direct effects on the States, the relationship between the national government and the States, or the distribution of power and responsibilities among the various levels of government; (2) imposes substantial direct compliance costs on State and local governments; or (3) preempts state law. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply. Nevertheless, during our review of the existing corrosion control standards, representatives of state pipeline safety agencies gave us advice both in private sessions and in the two public meetings we held. In addition, our pipeline safety advisory committees, which include representatives of state governments, were, on two occasions in 1999, briefed on the corrosion control review project.

Executive Order 13211. This rulemaking is not a ``Significant energy action'' under Executive Order 13211. It is not a significant regulatory action under Executive Order 12866 and is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, this rulemaking has not

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been designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.

List of Subjects in 49 CFR Part 195

Ammonia, Carbon dioxide, Incorporation by reference, Petroleum, Pipeline safety, Reporting and recordkeeping requirements.

In consideration of the foregoing, 49 CFR part 195 is amended as follows:

PART 195--[AMENDED]

1. The authority citation for part 195 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60118; and 49 CFR 1.53.

2. Section 195.3 is amended by adding paragraphs (b)(8) and (c)(7) to read as follows:

Sec. 195.3 Matter incorporated by reference.

* * * * *

(b) * * *

(8) NACE International, 1440 South Creek Drive, Houston, TX 77084.

(c) * * *

(7) NACE International (NACE):

(i) NACE Standard RP0169-96, ``Control of External Corrosion on Underground or Submerged Metallic Piping Systems' (1996).

(ii) [Reserved]

3. Section 195.5(b) is revised to read as follows:

Sec. 195.5 Conversion to service subject to this part.

* * * * *

(b) A pipeline that qualifies for use under this section need not comply with the corrosion control requirements of subpart H of this part until 12 months after it is placed into service, notwithstanding any previous deadlines for compliance.

* * * * *

4. Section 195.402(c)(3) is revised to read as follows:

Sec. 195.402 Procedural manual for operations, maintenance, and emergencies.

* * * * *

(c) * * *

(3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

* * * * *

Sec. 195.404 [Amended]

5. In Sec. 195.404, paragraph (a)(1)(v) is removed, and paragraphs (a)(1)(vi) through (a)(1)(viii) are redesignated as paragraphs (a)(1)(v) through (a)(1)(vii).

Secs. 195.236, 195.238, 195.242, 195.244, 195.414, 195.416, 195.418 [Removed]

6. The following sections are removed and reserved: Secs. 195.236, 195.238, 195.242, 195.244, 195.414, 195.416, and 195.418.
7. Subpart H is added to read as follows:

Subpart H--Corrosion Control

Sec.
195.551 What do the regulations in this subpart cover?
195.553 What special definitions apply to this subpart?
195.555 What are the qualifications for supervisors?
195.557 Which pipelines must have coating for external corrosion control?
195.559 What coating material may I use for external corrosion control?
195.561 When must I inspect pipe coating used for external corrosion control?
195.563 Which pipelines must have cathodic protection?
195.565 How do I install cathodic protection on breakout tanks?
195.567 Which pipelines must have test leads and how do I install and maintain the leads?
195.569 Do I have to examine exposed portions of buried pipelines?
195.571 What criteria must I use to determine the adequacy of cathodic protection?
195.573 What must I do to monitor external corrosion control?
195.575 Which facilities must I electrically isolate and what inspections, tests, and safeguards are required?
195.577 What must I do to alleviate interference currents?
195.579 What must I do to mitigate internal corrosion?
195.581 Which pipelines must I protect against atmospheric corrosion and what coating material may I use?
195.583 What must I do to monitor atmospheric corrosion control?
195.585 What must I do to correct corroded pipe?
195.587 What methods are available to determine the strength of corroded pipe?
195.589 What corrosion control information do I have to maintain?

Subpart H--Corrosion Control

Sec. 195.551 What do the regulations in this subpart cover?

This subpart prescribes minimum requirements for protecting steel pipelines against corrosion.

Sec. 195.553 What special definitions apply to this subpart?

As used in this subpart--
Active corrosion means continuing corrosion which, unless

controlled, could result in a condition that is detrimental to public safety or the environment.

Buried means covered or in contact with soil.

Electrical survey means a series of closely spaced pipe-to-soil readings over a pipeline that are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline.

Pipeline environment includes soil resistivity (high or low), soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion.

You means operator.

Sec. 195.555 What are the qualifications for supervisors?

You must require and verify that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures established under Sec. 195.402(c)(3) for which they are responsible for insuring compliance.

Sec. 195.557 Which pipelines must have coating for external corrosion control?

Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is--

(a) Constructed, relocated, replaced, or otherwise changed after the applicable date in Sec. 195.401(c), not including the movement of pipe covered by Sec. 195.424; or

(b) Converted under Sec. 195.5 and--

(1) Has an external coating that substantially meets Sec. 195.559 before the pipeline is placed in service; or

(2) Is a segment that is relocated, replaced, or substantially altered.

Sec. 195.559 What coating material may I use for external corrosion control?

Coating material for external corrosion control under Sec. 195.557 must--

(a) Be designed to mitigate corrosion of the buried or submerged pipeline;

(b) Have sufficient adhesion to the metal surface to prevent under film migration of moisture;

(c) Be sufficiently ductile to resist cracking;

(d) Have enough strength to resist damage due to handling and soil stress;

(e) Support any supplemental cathodic protection; and

(f) If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.

Sec. 195.561 When must I inspect pipe coating used for external corrosion control?

(a) You must inspect all external pipe coating required by Sec. 195.557 just prior to lowering the pipe into the ditch or submerging the pipe.

(b) You must repair any coating damage discovered.

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Sec. 195.563 Which pipelines must have cathodic protection?

(a) Each buried or submerged pipeline that is constructed, relocated, replaced, or otherwise changed after the applicable date in Sec. 195.401(c) must have cathodic protection. The cathodic protection must be in operation not later than 1 year after the pipeline is constructed, relocated, replaced, or otherwise changed, as applicable.

(b) Each buried or submerged pipeline converted under Sec. 195.5 must have cathodic protection if the pipeline--

(1) Has cathodic protection that substantially meets Sec. 195.571 before the pipeline is placed in service; or

(2) Is a segment that is relocated, replaced, or substantially altered.

(c) All other buried or submerged pipelines that have an effective external coating must have cathodic protection.\1\ Except as provided by paragraph (d) of this section, this requirement does not apply to breakout tanks and does not apply to buried piping in breakout tank areas and pumping stations until December 29, 2003.

\1\ A pipeline does not have an effective external coating material if the current required to cathodically protect the pipeline is substantially the same as if the pipeline were bare.

(d) Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where regulations in effect before January 28, 2002 required cathodic protection as a result of electrical inspections. See previous editions of this part in 49 CFR, parts 186 to 199.

(e) Unprotected pipe must have cathodic protection if required by Sec. 195.573(b).

Sec. 195.565 How do I install cathodic protection on breakout tanks?

After October 2, 2000, when you install cathodic protection under Sec. 195.563(a) to protect the bottom of an aboveground breakout tank of more than 500 barrels (79.5m3) capacity built to API Specification 12F, API Standard 620, or API Standard 650 (or its predecessor Standard 12C), you must install the system in accordance with API Recommended Practice 651. However, installation of the system need not comply with API Recommended Practice 651 on any tank for which you note in the corrosion control procedures established under Sec. 195.402(c)(3) why compliance with all or certain provisions of API Recommended Practice 651 is not necessary for the safety of the tank.

Sec. 195.567 Which pipelines must have test leads and what must I do to install and maintain the leads?

(a) General. Except for offshore pipelines, each buried or submerged pipeline or segment of pipeline under cathodic protection required by this subpart must have electrical test leads for external corrosion control. However, this requirement does not apply until December 27, 2004 to pipelines or pipeline segments on which test leads were not required by regulations in effect before January 28, 2002.

(b) Installation. You must install test leads as follows:

(1) Locate the leads at intervals frequent enough to obtain electrical measurements indicating the adequacy of cathodic protection.

(2) Provide enough looping or slack so backfilling will not unduly stress or break the lead and the lead will otherwise remain mechanically secure and electrically conductive.

(3) Prevent lead attachments from causing stress concentrations on pipe.

(4) For leads installed in conduits, suitably insulate the lead from the conduit.

(5) At the connection to the pipeline, coat each bared test lead wire and bared metallic area with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

(c) Maintenance. You must maintain the test lead wires in a condition that enables you to obtain electrical measurements to determine whether cathodic protection complies with Sec. 195.571.

Sec. 195.569 Do I have to examine exposed portions of buried pipelines?

Whenever you have knowledge that any portion of a buried pipeline is exposed, you must examine the exposed portion for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If you find external corrosion requiring corrective action under Sec. 195.585, you must investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

Sec. 195.571 What criteria must I use to determine the adequacy of cathodic protection?

Cathodic protection required by this subpart must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs 6.2 and 6.3 of NACE Standard RP0169-96 (incorporated by reference, see Sec. 195.3).

Sec. 195.573 What must I do to monitor external corrosion control?

(a) Protected pipelines. You must do the following to determine whether cathodic protection required by this subpart complies with Sec. 195.571:

(1) Conduct tests on the protected pipeline at least once each calendar year, but with intervals not exceeding 15 months. However, if tests at those intervals are impractical for separately protected short sections of bare or ineffectively coated pipelines, testing may be done

at least once every 3 calendar years, but with intervals not exceeding 39 months.

(2) Identify before December 29, 2003 or not more than 2 years after cathodic protection is installed, whichever comes later, the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE Standard RP0169-96 (incorporated by reference, see Sec. 195.3).

(b) Unprotected pipe. You must reevaluate your unprotected buried or submerged pipe and cathodically protect the pipe in areas in which active corrosion is found, as follows:

(1) Determine the areas of active corrosion by electrical survey, or where an electrical survey is impractical, by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(2) For the period in the first column, the second column prescribes the frequency of evaluation.

Period	Evaluation frequency
Before December 29, 2003..................	At least once every 5 calendar years, but with intervals not exceeding 63 months.
Beginning December 29, 2003...............	At least once every 3 calendar years, but with intervals not exceeding 39 months.

(c) Rectifiers and other devices. You must electrically check for proper performance each device in the first column at the frequency stated in the second column.

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Device	Check frequency
Rectifier.................................	At least six times each calendar year, but with intervals not exceeding 2\1/ 2\ months.
Reverse current switch....................	
Diode.....................................	
Interference bond whose failure would jeopardize structural protection.	
Other interference bond...................	At least once each calendar year, but with intervals not exceeding 15 months.

(d) Breakout tanks. You must inspect each cathodic protection system used to control corrosion on the bottom of an aboveground breakout tank to ensure that operation and maintenance of the system are in accordance with API Recommended Practice 651. However, this inspection is not required if you note in the corrosion control procedures established under Sec. 195.402(c)(3) why compliance with all or certain operation and maintenance provisions of API Recommended Practice 651 is not necessary for the safety of the tank.

(e) Corrective action. You must correct any identified deficiency in corrosion control as required by Sec. 195.401(b). However, if the deficiency involves a pipeline in an integrity management program under Sec. 195.452, you must correct the deficiency as required by Sec. 195.452(h).

Sec. 195.575 Which facilities must I electrically isolate and what inspections, tests, and safeguards are required?

(a) You must electrically isolate each buried or submerged pipeline from other metallic structures, unless you electrically interconnect and cathodically protect the pipeline and the other structures as a single unit.

(b) You must install one or more insulating devices where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

(c) You must inspect and electrically test each electrical isolation to assure the isolation is adequate.

(d) If you install an insulating device in an area where a combustible atmosphere is reasonable to foresee, you must take precautions to prevent arcing.

(e) If a pipeline is in close proximity to electrical transmission tower footings, ground cables, or counterpoise, or in other areas where it is reasonable to foresee fault currents or an unusual risk of lightning, you must protect the pipeline against damage from fault currents or lightning and take protective measures at insulating devices.

Sec. 195.577 What must I do to alleviate interference currents?

(a) For pipelines exposed to stray currents, you must have a program to identify, test for, and minimize the detrimental effects of such currents.

(b) You must design and install each impressed current or galvanic anode system to minimize any adverse effects on existing adjacent metallic structures.

Sec. 195.579 What must I do to mitigate internal corrosion?

(a) General. If you transport any hazardous liquid or carbon dioxide that would corrode the pipeline, you must investigate the corrosive effect of the hazardous liquid or carbon dioxide on the pipeline and take adequate steps to mitigate internal corrosion.

(b) Inhibitors. If you use corrosion inhibitors to mitigate internal corrosion, you must--

(1) Use inhibitors in sufficient quantity to protect the entire part of the pipeline system that the inhibitors are designed to

protect;

(2) Use coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion; and

(3) Examine the coupons or other monitoring equipment at least twice each calendar year, but with intervals not exceeding 7\1/2\ months.

(c) Removing pipe. Whenever you remove pipe from a pipeline, you must inspect the internal surface of the pipe for evidence of corrosion. If you find internal corrosion requiring corrective action under Sec. 195.585, you must investigate circumferentially and longitudinally beyond the removed pipe (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed pipe.

(d) Breakout tanks. After October 2, 2000, when you install a tank bottom lining in an aboveground breakout tank built to API Specification 12F, API Standard 620, or API Standard 650 (or its predecessor Standard 12C), you must install the lining in accordance with API Recommended Practice 652. However, installation of the lining need not comply with API Recommended Practice 652 on any tank for which you note in the corrosion control procedures established under Sec. 195.402(c)(3) why compliance with all or certain provisions of API Recommended Practice 652 is not necessary for the safety of the tank.

Sec. 195.581 Which pipelines must I protect against atmospheric corrosion and what coating material may I use?

(a) You must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (c) of this section.

(b) Coating material must be suitable for the prevention of atmospheric corrosion.

(c) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, you need not protect against atmospheric corrosion any pipeline for which you demonstrate by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will--

(1) Only be a light surface oxide; or

(2) Not affect the safe operation of the pipeline before the next scheduled inspection.

Sec. 195.583 What must I do to monitor atmospheric corrosion control?

(a) You must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

If the pipeline is located:	Then the frequency of inspection is:
Onshore..................................	At least once every 3 calendar years, but with intervals not exceeding 39 months.
Offshore.................................	At least once each calendar

year, but with intervals
not exceeding 15 months.

(b) During inspections you must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

(c) If you find atmospheric corrosion during an inspection, you must provide protection against the corrosion as required by Sec. 195.581.

Sec. 195.585 What must I do to correct corroded pipe?

(a) General corrosion. If you find pipe so generally corroded that the remaining wall thickness is less than that required for the maximum operating pressure of the pipeline, you must replace the pipe. However, you need not replace the pipe if you--

(1) Reduce the maximum operating pressure commensurate with the strength of the pipe needed for serviceability based on actual remaining wall thickness; or

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(2) Repair the pipe by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

(b) Localized corrosion pitting. If you find pipe that has localized corrosion pitting to a degree that leakage might result, you must replace or repair the pipe, unless you reduce the maximum operating pressure commensurate with the strength of the pipe based on actual remaining wall thickness in the pits.

Sec. 195.587 What methods are available to determine the strength of corroded pipe?

Under Sec. 195.585, you may use the procedure in ASME B31G, ``Manual for Determining the Remaining Strength of Corroded Pipelines,'' or the procedure developed by AGA/Battelle, ``A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe (with RSTRENG disk),'' to determine the strength of corroded pipe based on actual remaining wall thickness. These procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations set out in the respective procedures.

Sec. 195.589 What corrosion control information do I have to maintain?

(a) You must maintain current records or maps to show the location of--

(1) Cathodically protected pipelines;

(2) Cathodic protection facilities, including galvanic anodes, installed after January 28, 2002; and

(3) Neighboring structures bonded to cathodic protection systems.

(b) Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.

(c) You must maintain a record of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that corrosion requiring control measures does not exist. You must retain these records for at least 5 years, except that records related to Secs. 195.569, 195.573(a) and (b), and 195.579(b)(3) and (c) must be retained for as long as the pipeline remains in service.

Issued in Washington, DC on December 19, 2001.
Ellen G. Engleman,
Administrator.
[FR Doc. 01-31655 Filed 12-26-01; 8:45 am]
BILLING CODE 4910-60-P

[Federal Register: January 7, 2002 (Volume 67, Number 4)]
[Notices]
[Page 741-743]
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DEPARTMENT OF HEALTH AND HUMAN SERVICES

Substance Abuse and Mental Health Services Administration

Current List of Laboratories Which Meet Minimum Standards To Engage in Urine Drug Testing for Federal Agencies

AGENCY: Substance Abuse and Mental Health Services Administration, HHS.

ACTION: Notice.

SUMMARY: The Department of Health and Human Services notifies Federal agencies of the laboratories currently certified to meet standards of Subpart C of Mandatory Guidelines for Federal Workplace Drug Testing Programs (59 FR 29916, 29925). A notice listing all currently certified laboratories is published in the Federal Register during the first week of each month. If any laboratory's certification is suspended or revoked, the laboratory will be omitted from subsequent lists until such time as it is restored to full certification under the Guidelines.

If any laboratory has withdrawn from the National Laboratory Certification Program during the past month, it will be listed at the end, and will be omitted from the monthly listing thereafter.

This notice is also available on the internet at the following Web sites: http://workplace.samhsa.gov; http://www.drugfreeworkplace.gov; and http://www.health.org/workplace.

FOR FURTHER INFORMATION CONTACT: Mrs. Giselle Hersh or Dr. Walter Vogl, Division of Workplace Programs, 5600 Fishers Lane, Rockwall 2 Building, Room 815, Rockville, Maryland 20857; Tel.: (301) 443-6014, Fax: (301) 443-3031.

SUPPLEMENTARY INFORMATION: Mandatory Guidelines for Federal Workplace Drug Testing were developed in accordance with Executive Order 12564 and section 503 of Pub. L. 100-71. Subpart C of the Guidelines, ``Certification of Laboratories Engaged in Urine Drug Testing for Federal Agencies,'' sets strict standards which laboratories must meet in order to conduct urine drug testing for Federal agencies. To become certified an applicant laboratory must undergo three rounds of performance testing plus an on-site inspection.

To maintain that certification a laboratory must participate in a quarterly performance testing program plus periodic, on-site inspections.

Laboratories which claim to be in the applicant stage of certification are not to be considered as meeting the minimum requirements expressed in the HHS Guidelines. A laboratory must have its letter of certification from SAMHSA, HHS (formerly: HHS/NIDA) which attests that it has met minimum standards.

In accordance with Subpart C of the Guidelines, the following laboratories meet the minimum standards set forth in the Guidelines:

ACL Laboratories, 8901 W. Lincoln Ave., West Allis, WI 53227, 414-328-7840/800-877-7016 (Formerly: Bayshore Clinical Laboratory)
ACM Medical Laboratory, Inc. 160 Elmgrove Park, Rochester, NY 14624, 716-429-2264
Advanced Toxicology Network, 3560 Air Center Cove, Suite 101, Memphis, TN 38118, 901-794-5770/888-290-1150
Aegis Analytical Laboratories, Inc., 345 Hill Ave., Nashville, TN 37210, 615-255-2400
Alliance Laboratory Services, 3200 Burnet Ave., Cincinnati, OH 45229, 513-585-9000 (Formerly: Jewish Hospital of Cincinnati, Inc.)
American Medical Laboratories, Inc., 14225 Newbrook Dr., Chantilly, VA 20151, 703-802-6900
Associated Pathologists Laboratories, Inc., 4230 South Burnham Ave., Suite 250, Las Vegas, NV 89119-5412, 702-733-7866/800-433-2750
Baptist Medical Center--Toxicology Laboratory, 9601 I-630, Exit 7, Little Rock, AR 72205-7299, 501-202-2783 (Formerly: Forensic Toxicology Laboratory Baptist Medical Center)

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Clinical Laboratory Partners, LLC, 129 East Cedar St., Newington, CT 06111, 860-696-8115 (Formerly: Hartford Hospital Toxicology Laboratory)
Clinical Reference Lab, 8433 Quivira Rd., Lenexa, KS 66215-2802, 800-445-6917
Cox Health Systems, Department of Toxicology, 1423 North Jefferson Ave., Springfield, MO 65802, 800-876-3652/417-269-3093 (Formerly: Cox Medical Centers)
Diagnostic Services Inc., dba DSI, 12700 Westlinks Drive, Fort Myers, FL 33913, 941-561-8200/800-735-5416
Doctors Laboratory, Inc., P.O. Box 2658, 2906 Julia Dr., Valdosta, GA 31602, 912-244-4468
DrugProof, Divison of Dynacare, 543 South Hull St., Montgomery, AL 36103, 888-777-9497/334-241-0522 (Formerly: Alabama Reference Laboratories, Inc.)
DrugProof, Division of Dynacare/Laboratory of Pathology, LLC, 1229 Madison St., Suite 500, Nordstrom Medical Tower, Seattle, WA 98104, 206-386-2672/800-898-0180 (Formerly: Laboratory of Pathology of Seattle, Inc., DrugProof, Division of Laboratory of Pathology of Seattle, Inc.)
DrugScan, Inc., P.O. Box 2969, 1119 Mearns Rd., Warminster, PA 18974, 215-674-9310
Dynacare Kasper Medical Laboratories,* 14940-123 Ave., Edmonton, Alberta, Canada T5V 1B4, 780-451-3702/800-661-9876
ElSohly Laboratories, Inc., 5 Industrial Park Dr., Oxford, MS 38655, 662-236-2609
Express Analytical Labs, 3405 7th Avenue, Suite 106, Marion, IA 52302, 319-377-0500
Gamma-Dynacare Medical Laboratories,* A Division of the Gamma-Dynacare Laboratory Partnership, 245 Pall Mall St., London, ONT, Canada N6A 1P4, 519-679-1630
General Medical Laboratories, 36 South Brooks St., Madison, WI

53715, 608-267-6267
Kroll Laboratory Specialists, Inc., 1111 Newton St., Gretna, LA 70053 504-361-8989/800-433-3823 (Formerly: Laboratory Specialists, Inc.)
LabOne, Inc., 10101 Renner Blvd., Lenexa, KS 66219, 913-888-3927/ 800-728-4064 (Formerly: Center for Laboratory Services, a Division of LabOne, Inc.)
Laboratory Corporation of America Holdings, 7207 N. Gessner Road, Houston, TX 77040, 713-856-8288/800-800-2387
Laboratory Corporation of America Holdings, 69 First Ave., Raritan, NJ 08869, 908-526-2400/800-437-4986 (Formerly: Roche Biomedical Laboratories, Inc.)
Laboratory Corporation of America Holdings, 1904 Alexander Drive, Research Triangle Park, NC 27709, 919-572-6900/800-833-3984 (Formerly: LabCorp Occupational Testing Services, Inc., CompuChem Laboratories, Inc.; CompuChem Laboratories, Inc., A Subsidiary of Roche Biomedical Laboratory; Roche CompuChem Laboratories, Inc., A Member of the Roche Group)
Laboratory Corporation of America Holdings, 10788 Roselle Street, San Diego, CA 92121, 800-882-7272 (Formerly: Poisonlab, Inc.)
Laboratory Corporation of America Holdings, 1120 Stateline Road West, Southaven, MS 38671, 866-827-8042/800-233-6339 (Formerly: LabCorp Occupational Testing Services, Inc., MedExpress/National Laboratory Center)
Marshfield Laboratories, Forensic Toxicology Laboratory, 1000 North Oak Ave., Marshfield, WI 54449, 715-389-3734/800-331-3734
MAXXAM Analytics Inc.*, 5540 McAdam Rd., Mississauga, ON, Canada L4Z 1P1, 905-890-2555, (Formerly: NOVAMANN (Ontario) Inc.)
Medical College Hospitals Toxicology Laboratory, Department of Pathology, 3000 Arlington Ave., Toledo, OH 43699, 419-383-5213
MedTox Laboratories, Inc., 402 W. County Rd. D, St. Paul, MN 55112, 651-636-7466/800-832-3244
MetroLab-Legacy Laboratory Services, 1225 NE 2nd Ave., Portland, OR 97232, 503-413-5295/800-950-5295
Minneapolis Veterans Affairs Medical Center, Forensic Toxicology Laboratory, 1 Veterans Drive, Minneapolis, Minnesota 55417, 612-725-2088
National Toxicology Laboratories, Inc., 1100 California Ave., Bakersfield, CA 93304, 661-322-4250/800-350-3515
Northwest Drug Testing, a division of NWT Inc., 1141 E. 3900 South, Salt Lake City, UT 84124, 801-293-2300/800-322-3361, (Formerly: NWT Drug Testing, NorthWest Toxicology, Inc.)
One Source Toxicology Laboratory, Inc., 1705 Center Street, Deer Park, TX 77536, 713-920-2559, (Formerly: University of Texas Medical Branch, Clinical Chemistry Division; UTMB Pathology-Toxicology Laboratory)
Oregon Medical Laboratories, P.O. Box 972, 722 East 11th Ave., Eugene, OR 97440-0972, 541-687-2134
Pacific Toxicology Laboratories, 6160 Variel Ave., Woodland Hills, CA 91367, 818-598-3110/800-328-6942, (Formerly: Centinela Hospital Airport Toxicology Laboratory
Pathology Associates Medical Laboratories, 110 West Cliff Drive, Spokane, WA 99204, 509-755-8991/800-541-7891x8991
PharmChem Laboratories, Inc., 4600 N. Beach, Haltom City, TX 76137, 817-605-5300, (Formerly: PharmChem Laboratories, Inc., Texas Division; Harris Medical Laboratory)
Physicians Reference Laboratory, 7800 West 110th St., Overland Park,

KS 66210, 913-339-0372/800-821-3627
Quest Diagnostics Incorporated, 3175 Presidential Dr., Atlanta, GA 30340, 770-452-1590, (Formerly: SmithKline Beecham Clinical Laboratories, SmithKline Bio-Science Laboratories)
Quest Diagnostics Incorporated, 4770 Regent Blvd., Irving, TX 75063, 800-842-6152, (Moved from the Dallas location on 03/31/01; Formerly: SmithKline Beecham Clinical Laboratories, SmithKline Bio-Science Laboratories)
Quest Diagnostics Incorporated, 400 Egypt Rd., Norristown, PA 19403, 610-631-4600/877-642-2216, (Formerly: SmithKline Beecham Clinical Laboratories, SmithKline Bio-Science Laboratories)
Quest Diagnostics Incorporated, 506 E. State Pkwy., Schaumburg, IL 60173, 800-669-6995/847-885-2010, (Formerly: SmithKline Beecham Clinical Laboratories, International Toxicology Laboratories)
Quest Diagnostics Incorporated, 7470 Mission Valley Rd., San Diego, CA 92108-4406, 619-686-3200/800-446-4728 (Formerly: Nichols Institute, Nichols Institute Substance Abuse Testing (NISAT), CORNING Nichols Institute, CORNING Clinical Laboratories)
Quest Diagnostics Incorporated, 7600 Tyrone Ave., Van Nuys, CA 91405, 818-989-2520/800-877-2520 (Formerly: SmithKline Beecham Clinical Laboratories)
Scientific Testing Laboratories, Inc., 463 Southlake Blvd., Richmond, VA 23236, 804-378-9130
S.E.D. Medical Laboratories, 5601 Office Blvd., Albuquerque, NM 87109, 505-727-6300/800-999-5227
South Bend Medical Foundation, Inc., 530 N. Lafayette Blvd., South Bend, IN 46601, 219-234-4176
Southwest Laboratories, 2727 W. Baseline Rd., Tempe, AZ 85283, 602-438-8507/800-279-0027
Sparrow Health System, Toxicology Testing Center, St. Lawrence Campus, 1210 W. Saginaw, Lansing, MI 48915, 517-377-0520 (Formerly: St. Lawrence Hospital & Healthcare System)
St. Anthony Hospital Toxicology Laboratory, 1000 N. Lee St., Oklahoma City, OK 73101, 405-272-7052
Toxicology & Drug Monitoring Laboratory, University of Missouri Hospital & Clinics, 2703 Clark Lane, Suite B, Lower Level, Columbia, MO 65202, 573-882-1273
Toxicology Testing Service, Inc., 5426 N.W. 79th Ave., Miami, FL 33166, 305-593-2260
Universal Toxicology Laboratories (Florida), LLC, 5361 NW 33rd Avenue, Fort Lauderdale, FL 33309, 954-717-0300, 800-419-7187x419 (Formerly: Integrated Regional Laboratories, Cedars Medical Center, Department of Pathology)
Universal Toxicology Laboratories, LLC, 9930 W. Highway 80, Midland, TX 79706, 915-561-8851/888-953-8851
US Army Forensic Toxicology Drug Testing Laboratory, Fort Meade, Building 2490, Wilson Street, Fort George G. Meade, MD 20755-5235, 301-677-7085

* The Standards Council of Canada (SCC) voted to end its Laboratory Accreditation Program for Substance Abuse (LAPSA) effective May 12, 1998. Laboratories certified through that program were accredited to conduct forensic urine drug testing as required by U.S. Department of Transportation (DOT) regulations. As of that date, the certification of those accredited Canadian laboratories will continue under DOT authority. The responsibility for conducting quarterly performance testing plus periodic on-site inspections of

those LAPSA-accredited laboratories was transferred to the U.S. DHHS, with the DHHS' National Laboratory Certification Program (NLCP) contractor continuing to have an active role in the performance testing and laboratory inspection processes. Other Canadian laboratories wishing to be considered for the NLCP may apply directly to the NLCP contractor just as U.S. laboratories do.

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Upon finding a Canadian laboratory to be qualified, the DHHS will recommend that DOT certify the laboratory (Federal Register, 16 July 1996) as meeting the minimum standards of the ``Mandatory Guidelines for Workplace Drug Testing'' (59 FR, 9 June 1994, Pages 29908-29931). After receiving the DOT certification, the laboratory will be included in the monthly list of DHHS certified laboratories and participate in the NLCP certification maintenance program.

Richard Kopanda,
Executive Officer, Substance Abuse and Mental Health Services Administration.
[FR Doc. 02-277 Filed 1-4-02; 8:45 am]
BILLING CODE 4160-20-P

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[Rules and Regulations]
[Page 831-848]
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DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

49 CFR Part 195

[Docket No. RSPA-01-8663; Amdt. 195-75]
RIN 2137-AD56

Pipeline Safety: Hazardous Liquid Pipeline Accident Reporting Revisions

AGENCY: Office of Pipeline Safety, Research and Special Programs Administration, Department of Transportation.

ACTION: Final rule.

SUMMARY: This final rule makes changes to the reporting requirements for hazardous liquid pipeline accidents. The rule lowers the current release reporting threshold of 50 barrels to a new threshold of 5 gallons, and makes changes to the accident report form. The changes are necessary because the existing reporting threshold and report form do not yield sufficient information for effective safety analysis. This final rule also changes the ``bodily harm'' criteria for accident reporting to conform to the gas pipeline reporting requirements. This change is necessary to harmonize reporting by hazardous liquid and gas pipeline operators.

DATES: This rule is effective January 1, 2002.

FOR FURTHER INFORMATION CONTACT: Roger Little by phone at (202) 366-4569, by e-mail at roger.little@rspa.dot.gov, or by mail at the U.S. Department of Transportation (DOT), Research and Special Programs Administration (RSPA), Office of Pipeline Safety (OPS), Room 7128, 400 7th Street, SW., Washington, DC 20590.

SUPPLEMENTARY INFORMATION:

Background

The mission of RSPA's OPS is to ensure the safe, reliable, and environmentally sound operation of the nation's approximately 154 thousand miles of hazardous liquid pipelines. OPS shares responsibility for inspecting and overseeing the nation's pipelines with State pipeline safety offices. Both Federal and State regulators depend on accident reports submitted by pipeline companies to manage inspection programs and to identify trends in hazardous liquid pipeline safety. In recent years, Congress, the National Transportation Safety Board (NTSB) and DOT's Office of the Inspector General (OIG) have urged OPS to improve the quality of accident data required to be submitted by hazardous liquid pipeline operators.

Release Threshold

RSPA published a Notice of Proposed Rulemaking (NPRM) on March 20, 2001 (66 FR 15681). The NPRM proposed changing the hazardous liquid accident reporting requirement from a threshold release of 50 barrels to 5 gallons; and adding to the report form (RSPA F7000-1), more specific questions on accident location, causes, and consequences.

The NPRM also proposed that a spill under 5 barrels meeting all of the following criteria, need not be reported to RSPA:

(1) The other circumstances enumerated in Sec. 195.50 did not apply to the spill;
(2) The spill did not result in water pollution;
(3) The spill was attributable to a pipeline maintenance activity;
(4) The spill was confined to company property or pipeline right-of-way; and
(5) The spill was cleaned up promptly.

After consideration of all comments, this final rule amends the pipeline safety regulations to lower the reporting threshold for hazardous liquid pipeline releases from 50 barrels to 5 gallons, with an exception for spills under 5 barrels resulting from pipeline maintenance activities. This rule makes corresponding changes to the hazardous liquid accident report form to make it more useful for safety analysis.

The old report form consisted of two pages. The new report form consists of four pages. Completion of the first page only, is required for small releases (between 5 gallons and under 5 barrels) that are not reportable under the other Sec. 195.50 criteria, nor result in water pollution (water pollution is as described in Sec. 195.52(a)(4)). Completion of all four pages will be required for releases of: 5 barrels or more that are reportable under the other criteria in 49 CFR 195.50; or 5 gallons or more that result in water pollution.

Change in ``Bodily Harm'' Criteria for Accident Reporting

In another NPRM (Docket No. RSPA-99-6106; 65 FR 15290; March 22, 2000), RSPA proposed changing the ``bodily harm'' criteria in 49 CFR 195.50(e). RSPA proposed changing the language in 49 CFR 195.50(e) to require reporting only if an injury associated with a hazardous liquid pipeline accident requires hospitalization of the injured person.

The current language at Sec. 195.50(e) which triggers a reporting requirement reads as follows:

Bodily harm to any person resulting in one or more of the following:

(1) Loss of consciousness.
(2) Necessity to carry the person from the scene.
(3) Necessity for medical treatment.

(4) Disability which prevents the discharge of normal duties or the pursuit of normal activities beyond the day of the accident.

These criteria require reporting of even the most minor injury. The lack of a definition of medical treatment in the regulations means, if a bandage is applied at the scene the accident is reportable, even if it does not meet any of the other reportability criteria.

The comparable language in the gas pipeline safety rules requires gas operators to report releases of gas that involve a ``personal injury necessitating in-patient hospitalization.'' (49 CFR 191.3, 191.5, 191.9, and 191.15). As explained in the NPRM, this wording better describes the information that RSPA is seeking. Accordingly, RSPA proposed to update the hazardous liquid pipeline accident reporting requirements at Sec. 195.50(e) to eliminate the discrepancy between the accident reporting criteria for gas and hazardous liquid pipelines.

This final rule removes the language currently in Sec. 195.50(e) and replaces it with ``a personal injury necessitating in-patient hospitalization.''

Comments

Comments on Proposed Change in ``Bodily Harm'' Criteria

On May 3, 2000, the proposed changes in the injury criteria for reportability of hazardous liquid pipeline accidents were discussed at a joint meeting of the Technical Hazardous Liquid Pipeline Safety Standards Committee and the Technical Pipeline Safety Standards Committee. These statutorily mandated committees, which are made up of representatives from the government, industry, and the general public, review pipeline safety regulations. Some committee members expressed concern that the change would weaken the reporting requirements for hazardous liquid pipeline accidents. The concern was that some accidents that are reportable under the current language, would no longer be reportable under the proposed language.

We noted the proposed change would not cause any otherwise reportable hazardous liquid pipeline accident to

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become non-reportable. For example, under the proposed change, the 1994 San Jacinto River accident in Harris County, Texas, would still need to be reported based on product loss and property damage criteria. We also noted, most accidents causing serious injury are also reportable under one of the other criteria. The ``bodily harm'' category was included as a reporting criterion in the unlikely event that an accident resulting in such injury would not fall into one of the other reporting criteria. Additionally, we noted that the reporting language in Part 192, which embodies our original intent relative to the injury criteria for reportability of pipeline accidents, was adopted before the ``bodily harm'' language in part 195.

In response to the NPRM in Docket No. RSPA-99-6106, RSPA received comments from the American Petroleum Institute (API) and the Cascade Columbia Alliance.

API supported the proposed accident reporting criteria change in Sec. 195.50 to make the injury criteria consistent with that used for natural gas pipelines. It noted that the clarification makes reporting of accidents consistent across gas and hazardous liquid pipelines, and ``grew out of discussions among RSPA, the pipeline industry, and State regulators.'' In contrast, the Cascade Columbia Alliance asserted that the proposed injury language weakened reporting requirements for hazardous liquid pipelines and would ``encourage pipeline operators to avoid hospitalization for their workers so as to avoid filing an accident report.''

RSPA's intention for the change is to ensure that reporting of accidents is consistent for both gas and hazardous liquid pipelines. The regulation is not aimed at tracking worker injuries.

Comments on Lower Reporting Threshold

RSPA received comments from eleven sources in response to the NPRM in this docket (66 FR 15681; March 20, 2001). Virtually all commenters were supportive of the need for improved information about hazardous liquid pipeline accidents. The American Society of Safety Engineers supported the data improvement initiative and believed the benefits of the improved information would outweigh the small increased costs. The American Petroleum Institute (API) and the Association of Oil Pipe Lines (AOPL), trade associations that represent many companies involved in all aspects of the oil and gas industry, filed joint comments prepared in coordination with both API and AOPL's members.

Several commenters suggested that the $50,000 property damage threshold for an accident report was redundant and should be eliminated in light of the lowering of the volumetric release threshold for reporting from 50 barrels to 5 gallons. For the same reason, one commenter suggested that the $50,000 property damage threshold for telephonic notice of a release of hazardous material be eliminated.

The NPRM did not propose any change in the property damage threshold for filing accident report Form F7000-1. Although many ``over-$50,000-property-damage'' accidents may also be reportable under the 5 gallon threshold criterion, retaining the ``over-$50,000-property-damage'' criterion will continue to provide more complete data, than if eliminated. Changes to the telephonic reporting requirement are beyond the scope of the NPRM.

Several commenters believed we underestimated the time and cost of reporting the expanded information required by the revisions to Form F7000-1.

In response, we point the commenters to the analysis of costs in the ``Paperwork Reduction Act'' section of this Final Rule for more information on the basis of our estimates.

A group of students from Miami International University submitted four recommendations--

``(1) Given the twofold environmental effect of hazardous liquid or carbon dioxide spills to not only the immediate ground but also the atmosphere (air), and therefore, consequences realistic on any property, the reporting requirement should be lowered from 5 barrels to 10 gallons (38 liters) for spills on any property whether from accident or maintenance.

(2) Aggregate spills of hazardous liquid or carbon dioxide of a minimum of 10 gallons (38 liters) will pose sufficient damage to warrant immediate clean-up, and therefore, it should be mandated.

(3) Lowering the reporting requirement for spills from 5 barrels to 5 gallons (19 liters) only when it is not readily cleaned up on any property.

(4) Tools for Reporting Accidents (Sec. 195.50): Since technology

has evolved and continues to do so, accident reporting should be done in an efficient, cost-effective, time-constrained manner in tune with the technology available to us today. Furthermore, electronic accident reporting is effective and productive for meaningful incident information. The DOT, Office of Public [sic] Safety, should establish a web site where different accident report-hazardous liquid pipeline forms could be electronically filled out in case of an accident. Some of the benefits of electronic filing are: (i) instant information available, (ii) immediate dangers readily visible, and, (iii) reduced cost to companies. * * *"

In addition, API and Colonial Pipeline Company suggested that access to information both by RSPA, the public, and pipeline operators can be significantly improved by providing for electronic reporting of accidents. They urged us to move expeditiously to provide operators with the ability to file accident reports electronically.

We believe the bulk of hazardous liquid releases remain liquid at ambient temperatures, and therefore have little impact on the atmosphere. The exception is highly volatile liquid spills, which are gaseous at ambient temperatures. We have chosen to exclude from the reporting requirement hazardous liquid releases under 5 barrels that result from maintenance operations. Our information is that such spills occur regularly upon the opening of pipelines for insertion of spheres, smart pigs, or for routine inspections. The spills are usually caught in a berm or other containment device; are cleaned up immediately; and have little or no impact on the environment. We believe information on such releases would not be helpful in accident trending analysis. Maintenance spills must be promptly cleaned up to avoid the reporting requirement. Any non-maintenance spill of 5 gallons or more must be reported.

With regard to electronic reporting, we agree that electronic reporting is efficient and economical. Electronic reporting for hazardous liquid pipeline accidents will be available via the OPS Internet homepage at http://ops.dot.gov beginning January 1, 2002.

API and AOPL suggested reorganizing the sections in the accident report to simplify it. API suggested that [the] first page of [the] accident reporting form should be reorganized to clearly differentiate the information that must be provided for all spills from that which is required for those spills greater than 5 barrels." API also suggested that latitude and longitude should be collected for all spills, not just those greater than 5 barrels as proposed in the NPRM. API suggested that the causal categories for small accidents should ``use identical language to that for large spills (i.e., `Excavation' should be `Excavation damage or other outside force', `Material and Welds' should be `Material and/or weld failures,' `Operation should be `Incorrect Operation.' This will allow the longer

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form to provide insight for defining causes consistently across both types of releases." In addition, API suggested that instead of collecting spill quantity in two separate places on the form, that spill size be collected on page one for all spills.

We agreed with these comments and reorganized and changed the form as suggested.

API further noted that ``The instructions for the accident reporting form change the definition of `injury' for the purpose of accident reporting. The regulations must also be changed in Sec. 195.50

(reporting accidents) and Sec. 195.52 (telephonic notification). The changes in the definition for `injury' under the instructions will make hazardous liquid pipeline reporting requirements comparable to those for natural gas pipelines. These changes must be implemented in the regulations themselves under Sec. 195.50 and Sec. 195.52. The changes cannot be implemented through the reporting form or instructions alone."

We agree with the suggested change to Sec. 195.50(e) and adopted it. However, Section 195.52 was not the subject of the NPRM, and a change to that section would be beyond the scope of this rulemaking.

API suggested that categories for property damage should be modified to more accurately define the categories that are applicable and that make sense to pipeline operators. ``For accuracy, this section of the reporting form should be titled `Compensated losses.' Losses that accrue to the operator should be separated from losses that accrue to affected individuals or the public. Property damage or loss is really a misnomer. Although losses do occur, on this reporting form we are really accounting for damages for which an operator has provided reimbursement to the community, the public, or affected individuals. It is actually a measure of those losses that can in some way be reimbursed or losses that accrue to the operating company itself. API recommends that this portion of the accident form be redrafted as follows:

Compensated Losses (Estimated)

* Public/Community Losses:
--Estimated Public/private property damage reimbursed by operator. $
--Cost of emergency response undertaken by or reimbursed by operator. $
--Cost of longer term environmental remediation undertaken by or reimbursed by operator. $
--Other............................... $

Operator losses:
--Value of product lost............... $
--Value of operator property damage... $
--Other............................... $"

We adopted the API suggestions with some changes.

API also suggested that:

``Form Part F (environmental impacts), item 6 should be changed from `wildlife mortality' to `wildlife impact.' Mortality is too high a threshold for measuring the impact of accidents on wildlife. As an example, any bird that is oiled during an accident and survives is clearly impacted. We believe that a reasonable person would judge such oiling as an impact and expect that the industry be held to such a reasonable standard."

We agree and changed the form accordingly.

Colonial Pipeline Company (Colonial) recommended that additional information be added to Part G (Leak Detection Information) of the proposed accident form. Specifically, Colonial recommended that line items be added for ``estimated leak rate'' and ``estimated percentage of flow.'' Colonial believes this would provide valuable information to RSPA and the regulated community.

We may consider obtaining this additional information through a separate rulemaking.

Gregg Zimmerman, Administrator, Planning/Building/Public Works Department, with City of Renton, Washington, suggested that a ``requirement for immediate notification of the local public safety/ emergency management agencies is critical. These are the first line responders, and our experience shows us that often they are not contacted in the event of a leak for hours or even days. However, this requirement clearly should be part of the federal law, or at least the agency rules.''

We determined this recommendation to be beyond the scope of this rulemaking.

Enron Transportation Services (ETS) commented that ``[t]he availability of more detailed pipeline accident information is of value not only to OPS for regulatory purposes, but is also highly valued by the pipeline industry in identifying potential risks to pipeline safety and integrity. Most pipeline operators utilize this accident information to immediately evaluate their systems for the potential of similar risk factors and take steps to mitigate those factors on a timely basis whenever possible. ETS therefore strongly agrees that improving the method of accident data collection provides a benefit to the industry in being able to more reliably identify the cause of these accidents. Reducing the reporting limits to those proposed may indeed be counterproductive, however, in that the database will be flooded with information relating to minor pipeline problems as opposed to obtaining better information about potentially serious pipeline safety related issues. One of the reasons that the cost level limit for reportable accidents was raised in 1984 was to eliminate the reporting of non-significant pipeline accidents, and this proposed rulemaking will completely reverse that intent.''

We noted that the cost threshold for reporting accidents was raised in 1994 from $5,000.00 to $50,000.00 to achieve parity between reporting of hazardous liquid and natural gas pipeline accidents, not ``to eliminate reporting of non-significant pipeline accidents.'' Regarding ``flooding the database with information relating to minor problems,'' we believe the only way to determine that small spills are ``minor problems'' is to collect information on such spills.

ETS commented that ``the decision process for the determination of any pipeline remedial action should be the responsibility of the pipeline operator based upon that operator's assessment of the known risks and economic issues that only the operator must bear. Without first hand knowledge of all of the numerous factors that must be considered in making the repair versus replacement decision, this pipeline safety data may lead to hasty decisions that are not in the overall best interests of public safety. One of the consequences may be outside pressure to apply significant financial resources to a pipeline facility that presents a much lower risk to public safety than another less publicly visible facility.''

We recognize that it is industry's responsibility to determine when rehabilitation and replacement of any pipeline facility may be needed. We believe that better overall accident information will provide industry with a useful tool to help make better decisions about rehabilitation and replacement.

ETS noted that ``[t]he reduction in the spill reporting limit is noted in this section as being included in proposed bills now before Congress.'' ETS estimates that the low reporting limit is going to have a major impact on both the pipeline operators and DOT. Therefore, it believes the reporting limit should be established by Congress.

Based on outreach with the hazardous liquid pipeline industry and comments by that industry to the NPRM, we do not believe that a reduced spill reporting limit will have a major impact on pipeline operators because the additional burden to the pipeline

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industry to provide the data does not require significant effort. The additional data will improve the information available upon which to make safety decisions. Based on action thus far in Congress, we have no reason to believe that Congress would object to this final rule.

ETS also commented that ``* * * flooding the DOT accident database with numerous minor leaks or spills will ultimately bias the accident cause data and thereby mask the causes of more serious pipeline accidents that need to be addressed by DOT and the industry. This reporting requirement is also redundant in that data concerning leaks impacting bodies of water are already being documented under the applicable environmental regulations.''

We believe the accident database will not be flooded with minor releases because the proposed changes eliminate the need for reporting releases that occur during normal maintenance activities as described in the NPRM. We are focused on obtaining sufficient information about small releases to adequately categorize the risks posed by such accidents. At the same time we will obtain more precise information on spills of 5 or more barrels--information that is needed to further address safety issues. Although information on spills is being reported to environmental agencies under other regulations, we need to obtain this information to properly manage our pipeline safety responsibilities.

Tosco Corporation (Tosco) participated in an industry effort to accumulate information about releases that are now less than the current 50 barrel or more criteria. Tosco noted that ``information has been collected by a majority of the liquid industry on releases down to 5 gallons for the past few years. We believe it is critical information that can be used in the future for risk and integrity management efforts.'' Tosco also suggested that ``[t]he proposed * * * criteria for the non-reporting of releases of 5 gallons or more but less than 5 barrels may need to be better defined in the preamble to the final rule. Would a release occurring during the hydrostatic testing of a pipeline during maintenance activities that has a petroleum liquid as the test medium fall under this criteria?'' Tosco also commented that the revisions to the accident reporting form are ``well thought out'' and that the information that ``will be generated by this new form will indeed help to precisely detect trends in the causes of reportable pipeline accidents.''

We pointed out that releases meeting the requirements of the normal maintenance operations exception in the final rule need not be reported.

The Citizens Advisory Committee on Pipeline Safety (Washington State) ``disagreed with our proposal to reduce the threshold for reportable spills from the current level of 50 barrels to 5 gallons. The Committee stated that sufficient information can be acquired from pipeline operators by requiring reporting of incidents that are 1 (one) barrel or larger. The requirement of reporting all spills of 5 gallons or more appears to be more stringent than is required by good practice and necessary record keeping." OPS worked with a joint data team composed of State, Federal, and industry representatives to determine a reasonable accident reporting threshold. Higher reporting thresholds were considered, but we chose 5 gallons because we believe the benefit of reporting releases at the 5 gallon level outweighs the burden of collecting it. The benefit is in increased awareness of pipeline releases, especially the frequency of small spills. The data team believed that a higher threshold than 5 gallons would still leave concerns about the lack of information about such spills, especially if they impacted water.

The Minerals Management Service (MMS) of the U.S. Department of the Interior supported RSPA's efforts to improve pipeline accident data collection and analyses. MMS suggested that 49 CFR 195.1(b)(5) should be deleted since it includes jurisdictional criteria used prior to the 1996 Memorandum of Understanding (MOU) between MMS and OPS, which clarified each agency's jurisdiction over offshore pipeline facilities. MMS also questions whether the same reporting requirements and accident form would apply for a cumulative 5 gallons leaked from a pipeline slowly or intermittently over a period of weeks or months.

The NPRM did not address the jurisdictional issues raised by MMS. We are addressing those issues in a separate rulemaking. As for the intermittent leak scenario, 49 CFR 195.401(b) requires a hazardous liquid pipeline operator to correct within a reasonable time any condition that could adversely affect the safe operation of the pipeline system. We consider a release of hazardous material (a leak) from a pipeline to be a condition that must be promptly corrected.

Regulatory Analyses and Notices

Executive Order 12866 and DOT Polices and Procedures

RSPA does not consider this rulemaking to be significant under Section 3(f) of Executive Order 12866 (85 FR 51735; October 4, 1993). RSPA also does not consider this rulemaking to be significant under DOT Regulatory Policies and Procedures (44 FR 11034; February 20, 1979).

Benefits

The additional data that OPS will receive by lowering of the accident reporting threshold from 50 barrels to 5 gallons and the more detailed causation reporting, will enable RSPA and the hazardous liquid pipeline industry to better identify safety issues and trends in pipeline safety. Operators can then make informed decisions about changing their procedures to improve pipeline safety.

Costs

RSPA's revised form is composed of a ``short'' form (page one of the four page form for spills of less than 5 barrels as described above) and a ``long'' form of 4 pages for spills of 5 barrels or more, or spills to water as described above. We estimate that it will take each operator about 1 hour to complete the short form (2 minutes per field x 37 fields on short form) and that the long form will take about 7 hours to complete (2 minutes per fields x 224 fields). We recognize that some fields will take only a few seconds to complete and that some will take more than 2 minutes, but we estimate that the type of information requested on the long and the short forms will require 1 and 7 hours to complete, respectively. We also recognize that more time may be needed to collect the basic information required for completing the form, but we believe that companies already maintain this information as part of routine recordkeeping.

We estimate that the number of accidents reported annually will be 1,839. OPS extrapolated from data in the American Petroleum Institute (API) Pipeline Performance Tracking Initiative (PPTI), an anonymous reporting system that collects information on spills down to 5 gallons. Of the 1,839 annual reports, we estimate that 427 will require the long form and 1,412 will require the short form. Below is RSPA's estimates of the aggregate time required to complete the revised forms:

427 long forms x 7 hours = 2,989 hours.
1,412 short forms x 1 hour =1,422 hours.
Total: 1,839 forms; 4,411 hours

We estimated the hourly cost of the person completing the form would be $40. This was based on the U.S. Department of Labor's National Occupational Employment and Wage Earnings for 1999. The hourly wage for

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a Transportation, Storage, and Distribution Manager (the closest category to a pipeline manager) was $26.03 per hour. This was multiplied by 1.35 to account for fringe benefits ($26.03 x 1.35 = $35.14). We added an inflation factor of 14% to account for inflation from 1999 to 2002 ($35.14 x 1.14 = $40.05). If the average cost per hour is $40, the total annual industry cost is $176,440 annually (4,411 x $40 = $176,440).

The hazardous liquid pipeline industry historically files an average of 166 reports annually. Completion of each of these reports was estimated to take 6 hours, based on the time needed to research the information, or 996 hours annually (166 reports x 6 hours). At $40 per hour, the total industry cost averages $39,840 annually (996 x $40 = $39,840).

The net annual increase to the hazardous liquid pipeline industry resulting from the revisions to the reporting criteria and to the form is $136,600 ($176,440-$39,840 = $136,600). Dividing the incremental cost increase of $136,600 by approximately 200 hazardous liquid pipeline operators, the average incremental cost increase of this proposal is $683 per operator.

Comments

Two commenters, a pipeline operator and the Chief Counsel for Advocacy of the Small Business Administration (SBA), questioned RSPA's estimate of 7 hours to complete the long form. The SBA Chief Counsel for Advocacy wanted to know the basis for the 7 hour estimate.

We worked with a government/industry pipeline data team over the last several years to determine the extent of information that needed to be collected. RSPA is asking for only the most important information so as not to unduly burden pipeline operators. Moreover, the information requested on the revised form is not available from other sources.

We estimate that it will take each operator about 1 hour to complete the short form (2 minutes per field x 37 fields on short form) and that the long form will take about 7 hours to complete (2 minutes per fields x 224 fields). Electronic reporting of accidents, which will begin on January 1, 2002, should further reduce the time needed to complete the form. We believe this estimate is accurate based on these considerations.

Conclusion

RSPA believes that the additional cost of $136,600 annually is a minimal economic impact on the hazardous liquid pipeline industry. The benefits accruing to OPS and the pipeline industry; through the improvements in the quality of the information collected, should easily outweigh the cost.

Regulatory Flexibility Act

We sought input from the public on the impact of the proposed rule on small entities in the Notice of Proposed Rulemaking in this docket (66 FR 15681; March 20, 2001). No one responded to this request. The SBA Chief Counsel for Advocacy, however, made a few comments on behalf of small businesses. SBA asked the basis for using the short versus the long form. We described the usage of the short versus long form above. SBA also posed a question regarding how many operators RSPA would consider small. For several years, RSPA has sought public comment from small hazardous liquid operators. RSPA solicited public comment from small operators in its recent rulemakings on pipeline integrity management. No comments from small hazardous liquid operators were forthcoming.

The hazardous liquid pipeline industry is a highly competitive, capital intensive industry that has experienced many mergers and buyouts in recent years. SBA's criteria for defining a small entity in the hazardous liquid pipeline industry is 1,500 employees, as specified in the North American Industry Classification System codes (486110--Pipeline Transportation of Crude Oil and 486910--Pipeline Transportation of Refined Petroleum Products). We do not collect information on number of employees or revenues for pipeline operators. Such a collection would require OMB approval. However, we have discussed with SBA the characterization of hazardous liquid pipelines for purposes of this rulemaking. We intend to continue our dialog with SBA on its efforts to ascertain the number of small business operators in the hazardous liquid pipeline industry.

We made the following observations in assessing the effect of this rule on small businesses:

(1) Whether you characterize a hazardous liquid pipeline company as small or large, the cost is small in absolute terms. The average cost for all companies based on an estimated total impact of $136,600 annually is $683.00 per operator. We believe the benefits of this rule far outweigh the company cost.

(2) Assuming equal operating conditions across all pipeline mileage, the probability of having a reportable accident on a per mile basis is 1,839 expected reportable accidents per year over 154,000 miles of hazardous liquid pipeline, or about 1 reportable accident per hundred miles of pipeline. Companies with thousands of miles of pipe will typically have more reportable accidents than companies with hundreds of miles of pipe or less. Companies with less mileage will have a proportionately lower share of the estimated $136,600 annual cost posed by this rulemaking, for an average total per company cost of less than $683;

(3) We estimate that the nation's 80 largest hazardous liquid pipeline companies (based on pipeline mileage reported to RSPA by operators annually) operate more than 91% of the nation's total hazardous liquid pipeline mileage. About 120 companies operate the remaining 9% of mileage. Assuming this 9% of mileage were operated by

``small operators,'' these operators would experience no more than 9% of the reportable accidents and incur 9% or less of the $136,600 annual cost. This amounts to $12,294 total annual costs, or about $102 per company. Many of these 120 operators are, however, owned by or parts of nationally recognized large corporations, so the burden would actually be less than $102 per small business annually.

Based on the increase in costs to the industry of this rulemaking, RSPA certifies, pursuant to section 605 of the Regulatory Flexibility Act (5 U.S.C. 605), that this rulemaking would not have a significant impact on a substantial number of small entities.

Paperwork Reduction Act

This final rule contains information collection requirements as required by the Paperwork Reduction Act of 1995 (44 U.S.C. 3507 (d)). RSPA has previously submitted a copy of the Paperwork Reduction Act analysis to OMB for its review. The name of the information collection is ``Transportation of Hazardous Liquids by Pipeline: Record Keeping and Accident Reporting.'' The purpose of this information collection is to improve the current hazardous liquid pipeline accident information collection.

According to the Paperwork Reduction Act, no persons are required to respond to a collection of information unless a valid OMB control number is displayed. OMB has approved the revised form RSPA F7000-1 and this information collection. The OMB control number for this information collection is 2137-0047. For more details, see the Paperwork Reduction Analysis available for copying and review in the public docket.

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Executive Order 13175

This final rule has been analyzed in accordance with the principles and criteria contained in Executive Order 13175 (``Consultation and Coordination with Indian Tribal Governments''). Because this final rule does not significantly or uniquely affect the communities of the Indian tribal governments and does not impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13175 do not apply.

Executive Order 13132

This final rule has been analyzed in accordance with the principles and criteria contained in Executive Order 13132 (``Federalism''). This final rule does not adopt any regulation that (1) has substantial direct effects on the States, the relationship between the national government and the States, or the distribution of power and responsibilities among the various levels of government; (2) imposes substantial direct compliance costs on States and local governments; or (3) preempts State law. Therefore, the consultation and funding requirements of Executive Order 13132 (64 FR 43255; August 10, 1999) do not apply.

Executive Order 13211

This rulemaking is not a ``significant energy action'' within the meaning of Executive Order 13211 (``Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use.'') It is not a significant regulatory action under Executive Order 12866 and is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, this rulemaking has not been designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.

Unfunded Mandates

This rule does not impose unfunded mandates under the Unfunded Mandates Reform Act of 1995. It does not result in costs of $100 million or more to either State, local, or tribal governments, in the aggregate, or to the private sector, and is the least burdensome alternative that achieves the objective of the rule.

National Environmental Policy Act

RSPA has analyzed the final rule in accordance with section 102(2)(c) of the National Environmental Policy Act (42 U.S.C. 4332), the Council on Environmental Quality regulations (40 CFR 1500-1508), and DOT Order 5610.1D, and has determined that this action would not significantly affect the quality of the human environment, because information collection does not impact the environment.

List of Subjects in 49 CFR Part 195

Anhydrous Ammonia, Carbon dioxide, Incorporation by reference, Petroleum, Pipeline safety, Reporting and recordkeeping requirements.

For all the reasons described in this final rule, RSPA is amending Title 49, Part 195, Code of Federal Regulations, as follows:

PART 195--TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

1. The authority citation for part 195 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60118; and 49 CFR 1.53.

2. Amend Sec. 195.50 to revise paragraph (b), to remove paragraph (c), to redesignate paragraphs (d) through (f) as paragraphs (c) through (e) and revising the newly designated paragraphs, to read as follows:

Sec. 195.50 Reporting accidents.

* * * * *

(b) Release of 5 gallons (19 liters) or more of hazardous liquid or carbon dioxide, except that no report is required for a release of less than 5 barrels (0.8 cubic meters) resulting from a pipeline maintenance activity if the release is:

(1) Not otherwise reportable under this section;

(2) Not one described in Sec. 195.52(a)(4);

(3) Confined to company property or pipeline right-of-way; and

(4) Cleaned up promptly;
(c) Death of any person;
(d) Personal injury necessitating hospitalization;
(e) Estimated property damage, including cost of clean-up and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000.

Issued in Washington, DC, on December 21, 2001.
Ellen G. Engleman,
Administrator.
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[GRAPHIC] [TIFF OMITTED] TR08JA02.016

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[GRAPHIC] [TIFF OMITTED] TR08JA02.017

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[GRAPHIC] [TIFF OMITTED] TR08JA02.020

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DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

49 CFR Part 192

[Docket No. RSPA-00-7666; Notice 3]
RIN 2137-AD64

Pipeline Safety: High Consequence Areas for Gas Transmission Pipelines

AGENCY: Office of Pipeline Safety (OPS), Research and Special Programs Administration (RSPA), Department of Transportation (DOT).

ACTION: Notice of proposed rulemaking.

SUMMARY: The Research and Special Programs Administration (RSPA) is proposing to define areas of high consequence where the potential consequences of a gas pipeline accident may be significant or may do considerable harm to people and their property. This proposed rule is the first step in a two step process to address the integrity management programs for gas pipelines.

RSPA created the proposed definition from the comments received on the notice that invited further public comment about integrity management concepts as they relate to gas pipelines (Information Notice). Additionally, RSPA gathered information through a series of discussions and meetings with representatives of the gas pipeline industry, research institutions, State pipeline safety agencies and public interest groups. The proposed definition does not require any specific action by pipeline operators, but will be used in the pipeline integrity management rule for gas transmission lines that RSPA is currently developing.

DATES: Interested persons are invited to submit written comments by March 11, 2002. Late-filed comments will be considered to the extent practicable.

ADDRESSES:

Filing Information

You may submit written comments by mail or delivery to the Dockets Facility, U.S. Department of Transportation, Room PL-401, 400 Seventh Street, SW., Washington, DC 20590-0001. It is open from 10 a.m. to 5 p.m., Monday through Friday, except federal holidays. All written comments should identify the docket and notice numbers stated in the heading of this notice. Anyone desiring confirmation of mailed comments must include a self-addressed stamped postcard.

Electronic Access

You may also submit written comments to the docket electronically. To submit comments electronically, log on to the following Internet Web address: http://dms.dot.gov. Click on ``Help & Information'' for instructions on how to file a document electronically.

General Information

You may contact the Dockets Facility by phone at (202) 366-9329, for copies of this proposed rule or other material in the docket. All materials in this docket may be accessed electronically at http://dms.dot.gov.

FOR FURTHER INFORMATION CONTACT: Mike Israni by phone at (202) 366-4571, by fax at (202) 366-4566, or by E-mail at mike.israni@rspa.dot.gov, regarding the subject matter of this proposed rule. General information about the RSPA/OPS programs may be obtained by accessing OPS's Internet page at http://ops.dot.gov.

SUPPLEMENTARY INFORMATION:

Background

We are issuing integrity management program requirements for pipelines in several steps. RSPA began the series of rulemakings by issuing requirements pertaining to hazardous liquid and carbon dioxide pipeline operators. A final rule which applies to hazardous liquid operators with 500 or more miles of pipeline was published on December 1, 2000 (65 FR 75378). That rule applies to hazardous liquid and carbon dioxide pipelines that can affect high consequence areas, which include populated areas defined by the U.S. Census Bureau as urbanized areas or places, unusually sensitive environmental areas, and commercially navigable waterways. We issued a similar proposed rule for hazardous liquid operators with less than 500 miles of pipeline (66 FR 15821; March 21, 2001).

We are now beginning the integrity management rulemakings for gas transmission lines by first proposing a definition of high consequence areas. This definition will be entirely separate from the definition established for hazardous liquid pipelines. We will then propose requirements for gas transmission pipeline operators to develop and implement integrity management programs to provide additional protections to those areas. We are proceeding in two steps for several reasons. We gathered and reviewed a great deal of information on where the potential consequences of a gas pipeline accident may be significant or may do considerable harm to people and their property. We compared this information to the areas we currently require enhanced protections. We are, however, still collecting information on and verifying the validity of pipeline assessment methods other than internal inspection devices and pressure testing. Information on viable alternative assessment methods for gas transmission pipelines is critical to our proposal for an integrity management program. Unlike hazardous liquid pipelines, a large percent of gas transmission pipelines are not configured for the use of internal inspection devices or cannot be taken out of service for any length of time due to the disruption of critical gas supply to customers. Therefore, we must complete this work before we issue a proposal to address protections for gas pipelines in high consequence areas.

Additionally, while a consensus standard on implementing an overall integrity management program is complete, many consensus standards on pipeline integrity management that could be incorporated into an integrity rulemaking are still under development. Therefore, we decided to proceed with a definition based on information we analyzed, and continue work on proposed assessment and protection requirements for an integrity management program.

RSPA created this definition through a process which began with the goal of improving the assurance of pipeline integrity in those geographic areas where a rupture could have the most significant consequence on people. We thought it necessary to focus on those geographic areas to ensure that operators would expend resources in the areas where the benefits would be greatest, while the regulatory agencies and the industry continued to learn how to effectively improve integrity for the entire pipeline system.

We next assembled technical information to support development of rules to define the geographic areas of focus and prescribe the process to be used to increase the assurance of pipeline integrity. This was accomplished through a series of discussions and meetings with representatives of the gas pipeline industry, research institutions, State pipeline safety agencies and public interest groups. We digested the technical information from these meetings and developed preliminary hypotheses about how the rules should be structured. These hypotheses were documented in the Information Notice (66 FR 34318; June 27, 2001), which invited public comment both on the

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hypotheses and on the technical issues requiring resolution.

We developed the definition that we are proposing in this rulemaking based on the technical input received during the series of stakeholder meetings and the comments received on the Federal Register Notice. The use of this definition for areas of high consequence, in conjunction with implementation of future integrity management requirements, represents a major step in increasing the assurance of integrity for gas pipeline systems. Once integrity management program requirements are in place for the high consequence areas, RSPA will review the benefits achieved for future consideration of whether to extend integrity management requirements to other areas on pipelines. This review will also help us formulate effective practices to further enhance the integrity of the entire pipeline infrastructure.

RSPA's goal in developing the gas pipeline integrity management rules is to provide the regulatory structure required for operators to focus their resources on improving pipeline integrity in the areas where a pipeline failure would have the greatest impact on public safety. The RSPA philosophy toward gas pipelines is to build on current Class location regulations which require the operator to know what people by location would be impacted by a pipeline rupture, and to require added assurance of pipeline integrity in the areas where the population density is greatest.

These current Class location regulations, which are unique to gas pipelines, require an operator to periodically (typically done annually) monitor and record data on increases in population near its pipelines. Data monitoring gives a current and very accurate picture of where people live and work who could be affected by a pipeline release.

Since January 2000, RSPA has met with State agencies, representatives of the Interstate Natural Gas Association of America (INGAA), the American Gas Association (AGA), Battelle Memorial Institute, the Gas Technology Institute (GTI), Hartford Steam Boiler Inspection and Insurance Company, and operators covered under 49 CFR part 192. (See DOT Docket No. 7666 for summaries of the meetings.) We also met with the Western States' Land Commissioners, National Governors Association, National League of Cities, National Council of State Legislators, Environmental Defense, Public Interest Reform Group, and Working Group on Communities Right-To-Know.

From these meetings we gained a clearer understanding of four significant characteristics of gas pipelines that we used in developing a proposed definition of high consequence areas. First, the effects of a gas pipeline rupture and subsequent explosion are highly localized. The physical properties of natural gas dictate that it rises upward from a rupture or hole in the pipeline as the gas expands into the air. The observation of damage at the sites of pipeline ruptures confirmed this behavior of gas. Second, the zone of damage from an explosion and burning of gas following a pipeline rupture is related to the line's diameter and the pressure at which the pipeline is operated. Again, RSPA confirmed these patterns from observing the heat affected zone surrounding actual pipeline ruptures and explosions. We correlated these observations using a simplified mathematical model relating the properties of the gas, the pipe diameter, and the operating pressure to the predicted heat affected zone. Third, the size of the heat affected zone from pipeline ruptures where pipe diameter was less than 36 inches and operating pressures were at or below 1000 psig, was limited to a diameter of approximately 660 feet.

RSPA corroborated the size of the heat affected zone by observing the sites of actual ruptures. The size of the zone is also consistent with the current Class location definitions. This consistency is not surprising. Thirty-some years ago when the Class location regulations were developed, the 660 foot-wide zone around a pipeline was based on available data about a heat affected zone. However, at that time data only existed on pipeline failures where the pipe diameter was less than 36 inches and the operating pressures were lower than 1000 psig. The fourth piece of information relevant to our proposed definition is that the heat affected zone for pipelines of diameter equal to or greater than 36 inches, operating at pressures in excess of 1000 psig, can extend to as much as 1000 feet from the pipeline. The size of the zone for larger pipelines is based on mathematical models verified by comparison with data on the areas burned around actual gas pipeline ruptures.

On the dates of February 12-14, 2001, we held a public meeting in Arlington, VA, to discuss integrity management requirements for gas pipelines in high consequence areas, and ways to enhance communications with the public about hazardous liquid and gas pipelines. This meeting featured reports on the status of industry and government activities to improve the integrity of gas pipelines. Meeting attendees also participated in in-depth discussions on the integrity of gas pipelines.

The reports can be found in the DOT docket (#7666) and on the RSPA Web site under Initiatives/Pipeline Integrity Management Program/Gas Transmission Operators Rule.

At the public meeting, industry and State representatives presented their perspectives on a number of issues relating to integrity management. Several members of the public also made comments. Topics included:

Considerations for defining high consequence areas affected by gas pipelines;

Evaluation of design factors currently used for gas transmission pipelines;

Evaluation of performance history and experience with the impact zone in gas transmission failures;

Integrity management best practices and relationship between incident causes and industry practices;

Options for various forms of direct assessment of the integrity of gas pipelines, including costs and effectiveness;

Basis for establishing test pressure intervals;

Appropriateness of using pressure (stress) to differentiate integrity standards for pipelines

Status of research activities; and

Status of development of new national consensus standards.

These presentations can be viewed on the RSPA Web site under Initiatives/Pipeline Integrity Management Program/Gas Transmission Operators Rule.

We integrated the results from this meeting with the list of technical perspectives and issues that RSPA developed during the stakeholder meetings held over the previous twelve months. We then formulated the hypotheses on which we expected to base an integrity management rule and questions related to these hypotheses. We published both in a Federal Register Notice that we discuss in the next section.

Notice of Request for Comments

On June 27, 2001, RSPA issued a notice of request for comments (66 FR 34318) which asked for further information and clarification, and invited further public comment, on defining high consequence areas and developing integrity management requirements for gas transmission lines. In the notice, RSPA stated its objective to develop a rule on gas pipeline integrity management to address threats posed by pipeline segments in areas where the consequences of potential pipeline accidents pose the greatest risk

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to people and property, and provides additional protections for these areas. We had a similar objective when we developed the rules on liquid pipeline integrity management programs, although environmental protection played a larger role in those rules. We also advised on our intention to minimize any actual adverse impact of a new safety requirement on the supply of natural gas to customers.

In the notice, we described the seven elements we believed should be included in any gas pipeline integrity management rule. We used similar elements in developing the liquid pipeline integrity management rules. These elements were based on certain hypotheses we discussed in detail in the notice. Then, we invited comment about these elements and hypotheses. The notice further summarized the areas where RSPA was seeking further information before proposing an integrity management program rule for gas operators. We categorized these information needs into nine categories, seven of which were the elements we described as essential to any integrity management program rule. The other two categories were to seek information about the costs of an integrity management rulemaking, and the rule's potential impact on gas supply.

The first element we discussed was how to define high consequence areas, i.e., those areas where the potential consequences of a gas pipeline accident may be significant or may do considerable harm to people and their property. We put forth the following hypotheses for comment:

Data from sites where gas pipelines ruptured and exploded show that the range of impact of such explosions is limited. Therefore, the area in which nearby residents may be harmed or there may be property damaged by potential pipeline ruptures, can be mathematically modeled as a function of the physical size of the pipeline and the material transported (typically, but not exclusively, natural gas).

Because we require gas pipeline operators to maintain data on the number of buildings within 660 feet of their pipelines, the definition of potentially high consequence areas where additional integrity assurance measures are needed should incorporate these data.

The range of impact from the rupture and explosion of very large diameter (greater than 36 inches) high pressure (greater than 1000 psi) gas pipelines is greater than the 660 feet currently used in the regulations.

Special consideration must be given to protect people living or working near gas pipelines who would have difficulty evacuating the area quickly (e.g., schools, hospitals, nursing homes, prisons).

Due to the relatively small radius of impact of a gas pipeline rupture and subsequent explosion, and the behavior of gas products, environmental consequences are expected to be limited. At this time, RSPA has little information to indicate the definition of high consequence areas near gas pipelines should include environmental factors.

Given that pipeline operators maintain extensive data on the distribution of people near their pipelines, RSPA intends for operators to use these data, together with a narrative definition of a high consequence area (defined by RSPA), to identify the specific locations of high consequence areas.

Electronic Discussion Forum

To promote greater discussion of these issues, RSPA also initiated an electronic discussion forum which was open from June 27 through August 13, 2001, at the RSPA Web site under the subheading ``More Information Needed on Gas Integrity Management Program.'' A transcript of the electronic discussion forum is placed in this docket. Comments received relevant to a definition of high consequence areas are discussed here.

Comments to FR Notice on Integrity Management Concepts and Hypotheses (Gas Transmission Pipelines)

Comments to the docket were provided by one state public service agency, five industry associations (including one association of industrial gas consumers), sixteen companies or groups of companies that operate gas pipelines, one company that operates hazardous liquid pipelines, and one company that builds pipeline bridges. In this document we summarized the comments relating to the first element--Defining High Consequence Areas. We will summarize and discuss comments on the remaining elements when we propose a rule on requirements for gas pipeline integrity management programs.

Define the Areas of Potentially High Consequence

This element of a rule would define the areas where the potential consequences of a gas pipeline accident may be significant or may do considerable harm to people and property. In the Information Notice, we discussed a model that was presented at the February public meeting relating gas pipeline diameter and operating pressure to the physical boundaries of the area impacted by the heat from a gas pipeline rupture and subsequent fire. C-FER, a Canadian research and consulting organization, developed the model which predicted the extent of the heat affected zone would be 660 feet for pipelines of up to 36 inches diameter and operating at pressures up to 1000 psig, and 1000 feet for larger pipelines operating at 1000 psig or higher. The model used 5000 BTU/hr-ft\2\ as the critical heat flux for defining the impact radius. We requested comment on the validity of this model, and of any other models that could be used in developing a definition. We requested comment on the validity of limiting an impact zone to areas where there are more than 25 houses or a facility housing people of limited mobility.

We requested comment on the feasibility of including all populous areas where the impact radius could exceed 660 feet, and of including high traffic roadways, railways and places where people are known to congregate, such as, churches, beaches, recreational facilities, museums, zoos, and camping grounds. We also requested further information on the impacts of a gas release on areas of environmental significance, and for comment on including any of these areas in a definition.

Comments

AGA and APGA, trade associations representing investor-owned and municipally-owned gas utilities, submitted joint comments. They stated that high consequence areas should be defined by class location, census-based population data and the zone of influence analysis in the C-FER report. They commented that operators collect and use information establishing class location and that such data can be readily incorporated into a definition, but they believe census data should also be an option.

While AGA and APGA agreed with providing special protection for facilities housing people with limited mobility, they maintained that identifying these facilities may be very difficult if they are not licensed and listed by a city or state. They further maintained that it is not appropriate to analyze every place where people may congregate or every roadway intersection, because this information is very dynamic and would be very difficult to keep current. These associations also argued against including commercially navigable waterways or environmentally sensitive areas because Congress did not mandate

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these areas be included in a gas pipeline integrity rule, and a gas release would not present a significant risk to these areas.

AGA and APGA argued that requiring operators to maintain and submit detailed population data is inefficient. They pointed out that some operators do not keep current data on populations near their pipelines, but rather treat all lines as though they were Class 4. Also, that for older pipelines, the most available record would be the class location distribution along their pipelines.

AGL Resources, Inc., a parent company of Atlanta Gas Light Co., Chattanooga Gas Co., and Virginia Natural Gas, supported using the current definitions of Class 3 and 4 locations because the large majority of their transmission lines are designed to operate in class 4 locations. .

The Association of Texas Intrastate Natural Gas Pipelines commented that using class locations to define high consequence areas would be appropriate since operators already maintain this information. The Association recommended we only include additional criteria that can be applied uniformly across all pipeline systems, such as class locations where the impact radius exceeds 660 feet. The Association argued against including high traffic roadways and places where people are known to congregate because these areas would be too subjective and therefore difficult to interpret or enforce uniformly. The Association maintained that although gas pipelines pose insignificant environmental risks, it would be appropriate to require operators to evaluate their systems to determine areas where condensate or other liquids are known to accumulate, and where a rupture would lead to release of these liquids near sensitive wildlife areas or bodies of water.

Baltimore Gas & Electric Company (BG&E), a natural gas distribution system operator, commented that a definition should incorporate non-population factors, particularly those based on the risk posed by a pipe segment, not simply the consequences of failure. BG&E also stated that the definition should differentiate transmission pipelines which are part of a distribution system where they are closely coupled to the distribution process, but did not suggest how to do this.

Chevron Pipe Line Company (CPL) supported protecting areas with facilities housing people unable to evacuate the area quickly. CPL was not in favor of including places where people congregate, because CPL thought the term too broad and it could easily encompass the entire length of a pipeline thereby diluting the focus on enhancing integrity in high risk areas.

Consumers Energy Company did not agree with defining high consequence area primarily by population density. Rather, Consumers Energy thought other factors that affect the overall risk a pipeline poses should be considered, such as pipeline operations, performance history and wall thickness.

El Paso Pipeline Group, an operator of five major natural gas transmission pipelines, commented that a definition should protect those areas where population density is greatest. El Paso urged RSPA to develop a workable definition which would take into consideration that operators have been collecting land use data relating to dwellings and other structures located within 660 feet of their pipelines. El Paso further urged RSPA to rely on the Gas Research Institute (GRI) study, dated December, 2001 (GRI-00/0189--``A Model for Sizing High Consequence Areas Associated With Natural Gas Pipelines'') because this study shows that the impact on the heat-affected zone depends on many factors beyond the heat flux value. Due to many factors involved, El

Paso was in favor of the value used in the C-FER analysis as a reasonable value.

Enron Transportation Services (ETS) commented that using the current definitions of Class 3 and 4 locations would allow operators to integrate the existing population data they maintain (data on populated areas within 660 feet of a pipeline) into an integrity management plan. ETS maintained that the current definitions of class 3 and 4 areas should pick up less densely-populated areas on the fringe of these areas. ETS recommended that a definition include locations of facilities housing people of impaired mobility because these locations are consistent with the purpose of the class location process. ETS further added that many operators are already locating these facilities as part of their class location survey determination. ETS also supported the critical heat flux value used in the C-FER analysis as a reasonable value for evaluating a high consequence area.

ETS was against including crossings of roads and railways because of the low relative risk posed by pipelines at these locations, compared to the risk presented by vehicle and train traffic. ETS maintained that patrols of these locations, as the pipeline safety regulations currently require, will identify any potential problems. ETS further argued that places where the public congregates are already treated as populated areas requiring an increased level of protection. As for environmental areas, ETS commented that natural gas presents little threat to water and many pipeline rights-of-way have already had cultural resource clearance. Although ETS did not dispute that a threatened species or habitat could be affected, it did not want such areas generally included. ETS recommended operators treat such areas on a case-by-case basis, but such areas not be mapped for security reasons (e.g., the sole remaining habitat of a threatened or endangered species).

INGAA, a trade organization which represents interstate natural gas transmission pipeline companies, offered several comments about the hypotheses for the high consequence area definition. INGAA explained the 660-foot radius used in developing part 192 was based on photographs of actual burn areas from the ignition of a pipeline rupture; however, in 1970, few pipelines larger than 30 inches in diameter or operating at pressures higher than 1000 psig existed. INGAA further explained that the 5000 BTU/hr-ft\2\ radiation heat flux used in the C-FER model was developed as part of an integrated analysis to define the heat affected zone around a ruptured natural gas pipeline and the results of this analysis were validated against data on the extent of the burn zone from actual pipeline ruptures. INGAA explained that this model produced a 660-foot radius circle for a 30-inch diameter pipeline operating at 1000 psig. INGAA did not see why the methodology could not be applied to a pipeline transporting hydrogen.

INGAA stated that a 25-house limit for a high impact zone is consistent with the definition for hazardous liquid pipelines, where a population density of 1000 people or more per square mile was used. INGAA maintained that this translates to 25 houses within a circle of 660-foot radius, assuming two people per house. INGAA further argued that based on typical Class 3 population density, 25 houses is an appropriate number and consistent with class location regulations.

INGAA argued that it would be too expensive to collect data on areas beyond the 660-foot radius. However, INGAA would support extending the area of protection beyond the 660-foot corridor for structures containing concentrations of people with limited mobility, such as, hospitals, schools, childcare facilities, retirement communities or prisons. INGAA explained that this is consistent with the current draft of the Integrity

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Management Appendix to American Society of Mechanical Engineers (ASME) B31.8 Std.

INGAA argued that current definitions for Class 3 and 4 areas probably cover many areas where people congregate. INGAA acknowledged that high traffic roadways and railways would not be covered if they were not already in Class 3 and 4 areas, but thought these areas are probably addressed through design, construction, operation and maintenance requirements.

INGAA was opposed to including any environmental areas in the definition. INGAA explained that methane releases would inflict very limited collateral damage to wildlife and would not impact water supplies.

Keyspan Energy Delivery, a local distribution company (LDC), was in favor of defining high consequence areas as Class 3 and 4 locations because its lines comply with the requirements for these class locations. Keyspan was also in favor of clearly defined areas, but wanted any definition to recognize that LDCs cannot precisely evaluate and re-evaluate such areas. Keyspan recommended a definition which would allow for performance-based variables but did not provide any examples.

Kinder Morgan, Inc., a large midstream energy company, favored a definition of high consequence areas which uses a model, such as the one C-FER developed, relating pipeline diameter and operating pressure to the physical boundaries of the area of impact. Kinder Morgan recommended further that we use a sliding approach where high consequence areas would be defined as areas of high population density within the C-FER defined hazard area. Kinder Morgan maintained that areas where people congregate are currently covered in the definition of Class 3, and that these areas should be included in the high consequence area definition only if they are located within the defined hazard area for a given pipeline.

MidAmerican Energy Company, a combination gas and electric utility, generally agreed with the definitions recommended by AGA/APGA and INGAA, because these definitions would not impact its operations. MidAmerican commented that if high traffic roadways are included they need to be clearly defined, and suggested definitions. MidAmerican also clarified that including places where people congregate would have minimal impact on its operations.

The New York Gas Group (NYGAS), a natural gas utility trade association, suggested we replace the term high consequence area with a less inflammatory term such as Affected Area. NYGAS agreed with including Class 3 and 4 locations but argued that it will be virtually impossible for local distribution companies to identify facilities housing people with impaired mobility unless such facilities are licensed or are on a list that an operator can obtain. NYGAS was opposed to using census data to determine a high consequence area, because they believe the data is not accurate and is updated every ten years. NYGAS did not support including high traffic roadways, railways and places where people congregate in the definition because of the uncertainty and complexity of trying to include these elements.

New York State Department of Public Service (NYDPS) commented that in addition to facilities housing people with limited mobility, consideration should be given to special features near pipelines, such as places of public assembly, historical landmarks, parks, bridges, power line corridors, other pipeline facilities, major roadways, and railways.

NYDPS supported the concept of an impact radius for determining high consequence areas, but contended that the C-FER model (using 5000 BTU/hr-ft\2\) conveniently results in an impact radius of about 660 feet. Based on this outcome, NYDPS believes the impact zone will never extend beyond the current class location for most operators. NYDPS suggested defining a more appropriate critical heat flux value (one lower than the C-FER model) so the impact radius could extend beyond the 660 feet.

The Energy Distribution Segment of NiSource Inc. (NiSource EDG), which is comprised of ten distribution companies, expressed concern that basing a high consequence area on the potential for considerable harm, would be too expansive to be of any practical value. NiSource EDG thought that a definition should consider the number of persons who might be harmed, as well as the potential significance of the harm, and that it should also include identifiable physical locations where people are unable to evacuate or to take protective actions.

NiSource EDG was against basing an impact zone on the number of houses, because data from which an operator could extrapolate the number of houses might not exist. NiSource explained that because many local distribution companies design their systems to be consistent with the requirements of a Class 4 location, they do not monitor housing distribution data near their pipelines. Therefore, NiSource EDG argued, imposing criteria which would require local distribution companies to initiate class location surveys would delay implementation of a rule, increase administrative and record-keeping burdens, and be extremely expensive.

NiSource argued against including an environmental component in the definition, and against including what it maintained were nebulous areas, i.e., high traffic roadways, railways, and places where people congregate.

Pacific Gas and Electric Company (PG&E), a utility subsidiary of PG&E Corporation, supported the use of structure data but noted that once a class location reaches 3, the structure data is no longer accumulated or may not be kept current. PG&E proposed that operators be allowed to use third party data sources which address the location of high consequence structures, as well as census data to determine whether housing density could reach or exceed 25 structures within a circle defined by an analysis such as the C-FER model. PG&E supported use of the C-FER model for larger diameter pipelines, and supported allowing more extensive models for operators that choose to perform a more detailed analysis of the impact zone following a pipeline rupture. PG&E supported including day-care facilities with more than 25 people, but was opposed to including any environmental component in a definition.

Tosco Corporation, an independent refiner and marketer of gasoline and other petroleum products, and a pipeline owner and operator, was in favor of using existing class 3 and 4 location criteria. Tosco also believed that other relevant factors must be considered in determining how to protect an area beyond 660 feet from the pipeline, such as line diameter, line pressure and local environmental conditions. Tosco was opposed to micro-determining a high consequence area down to a foot basis, as maintaining data on such precise areas could be unmanageable. Tosco was not in favor of using census data to define its high consequence areas, rather, it favored counting structures within 660 feet of a pipeline.

Electronic Forum Comments

A commenter to the electronic forum reminded RSPA that the Carlsbad, New Mexico, failure happened in a low consequence area, and high consequence areas should be defined as areas where there is a high probability that the pipeline could be damaged by outside forces.

Another commenter from a school facilities planning division argued that

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schools are extremely high consequence areas and should be explicitly mentioned.

The Proposed Rule

RSPA's goal for the gas integrity management rules (the definition and the integrity program requirements) is to provide greater assurance of pipeline integrity in geographic areas where a gas pipeline rupture could do the most harm to people. Through our proposed definition of high consequence areas, and the integrity management program requirements now under development, we will ensure that an operator's resources are expended on areas where the benefits will be the greatest. Once we propose and implement the integrity management program requirements for the areas we define, we will study the results and consider how effective it would be to extend added protection to other areas.

The areas we propose to define as high consequence areas for gas transmission pipelines are different from those we defined for hazardous liquid pipelines (see 49 CFR 195.450). The areas we defined for hazardous liquid pipelines were without regard to where the pipeline was located; whereas the proposed areas for gas transmission pipelines are defined with respect to a zone around a pipeline. Furthermore, certain sensitive environmental areas were included in the high consequence areas for hazardous liquid pipelines but are not included in the proposed definition for gas pipelines. The differences are due to differences in the physical properties of the products and consequences of a gas release versus a hazardous liquid release, and the benefits of having accurate data on population already maintained by gas transmission operators.

Due to the physical properties of gas, the rupture of a gas pipeline impacts a very limited area adjacent to the location of the rupture. In contrast, when a liquid pipeline ruptures, the liquid can flow a greater distance from the site of the rupture. Furthermore, unlike a liquid release, the rupture of a gas pipeline cannot lead to far-reaching damage to habitats of threatened or endangered species. Moreover, gas released from a pipeline rupture flows upward into the air following a rupture, and so cannot pollute drinking water or ecological resources.

RSPA based the population component of the definition for hazardous liquid pipelines on the U.S. Census Bureau's definition of urbanized areas and places. As hazardous liquid operators are not required to maintain population data, we decided to use the U.S. Census Bureau's definitions because they were the best available data on population adjacent to hazardous liquid pipelines. In contrast, because gas pipeline safety requirements are structured according to class location (i.e., population density), gas pipeline operators already maintain current data on the location of people in areas adjacent to their pipelines. We are confident this data is accurate. Thus, it seemed logical to structure a definition that would use the data pipeline companies already collect and maintain.

Nonetheless, even though the we structured the gas pipeline high consequence areas differently from the hazardous liquid high consequence areas, the inclusion of both Class 3 and 4 locations in the proposed definition is consistent with the census-defined areas encompassing population density of approximately 1000 people per square mile. In Class 3 locations, the lower limit on occupied buildings in a sliding mile is 46 (i.e., an area one mile long and 1320 (2 x 660) feet wide), which is equivalent to a population density of 460 people per square mile assuming 2.5 people per building. Other populated areas included in the hazardous liquid definition are picked up in the proposed definition by the lower population density value used in the Class 3 location definition and by including isolated buildings near a pipeline that house people with limited mobility.

RSPA's proposed definition of high consequence areas for gas transmission pipelines extends to areas beyond current class locations, or in other words, beyond areas where operators are currently required to have data. Our analysis of data on the area affected by a pipeline accident, demonstrated the need for special consideration of buildings located more than 300 feet from the pipeline that house people with limited mobility. It also demonstrated a need for consideration of areas near gas pipelines of diameter greater than 30 inches and operating at pressures in excess of 1000 psig. Therefore, we are including in the proposed definition, areas out to 660 feet from a pipeline (1000 feet from a pipeline with a diameter greater than 30 inches and operating at a pressure greater than 1000 psig) where there are buildings housing people with limited mobility and areas where people congregate. Although operators are not currently required to maintain data on these areas, operators are required to patrol their pipeline right-of-way. Based on these requirements, we believe operators should have knowledge of where people congregate near their pipeline. Additionally, this information should be available from local public safety officials.

Our basis for extending the area to 1000 feet is based on the C-FER model, previously discussed in this document. (Their report is in Docket #7666). The C-FER Model demonstrated that large diameter pipe (greater than 30 inches) operated at pressures greater than 1000 psig has the potential to impact an area greater than 660 feet from the pipeline. The C-FER analysis was based on a simplified model of a gas pipeline rupture. The model included simplified mathematical treatment of several phenomena important to characterizing the extent of damage following a pipeline rupture (for example, critical heat flux, the time of ignition of the escaping gas, the height of the burning jet, the pipe decompression rate). The model also included estimates of several important parameters associated with the phenomena. Due to the simplifications in the model and the need to select values for the key parameters, the model was validated by comparing its predictions with the results of actual incidents for which the burn radius (area around the rupture which experienced damage) associated with a pipeline rupture and ignition could be measured. The C-FER report shows these comparisons between model predictions and observed burn areas. The comparisons appear to validate the predictive ability of the model.

High Consequence Areas

We considered the comments and information received in response to the hypotheses presented in the Information Notice. We developed a proposed definition of high consequence areas for gas transmission pipelines based on the hypotheses and comments, as well as our extensive analysis of technical information from diverse sources. Our primary concern is with protecting populated areas from a gas release. Therefore, we are proposing to include the following class location areas, which are already defined in part 192. We concluded that these areas will encompass about 85% of populated areas, which is comparable to the percentage of populated areas picked by the hazardous liquid definition using the Census Bureau's definitions. These are the areas where gas transmission pipeline operators maintain data on population and buildings near their pipelines.

Class 3 areas. Class 3 areas are defined in the pipeline safety regulations as a class location unit with 46 or more buildings intended for

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human occupancy. A class location unit is an area that extends 220 yards on either side of the centerline of any continuous one-mile length of pipeline. A class 3 area is also an area where the pipeline lies within 100 yards of either a building or a small, well-defined outside area, such as a playground, recreation area, outdoor theater, or other place of public assembly, which is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. Neither the days nor the weeks need be consecutive.

Class 4 areas. Class 4 areas are any class location unit which include buildings with four or more stories.

We are proposing to extend the definition of areas of high consequence beyond the class location areas. We analyzed the C-FER model against RSPA accident data and concluded that a release from most pipelines would not affect an area greater than 660 feet. However, we also want to ensure that areas where there are facilities with people who may not be able to evacuate an area quickly are better protected from the likelihood of a pipeline release. Therefore, we propose to define these areas as follows:

An area where a pipeline lies within 660 feet of a hospital, school, day-care facility, retirement facility, prison or other facility having persons who are confined, are of impaired mobility, or would be difficult to evacuate.

With the use of a commercial database, we are collecting data on the locations of these facilities to help identify these areas.

Our research further demonstrates that a rupture or release from a larger-sized pipeline would likely affect an area beyond 660 feet, i.e., those pipelines that are more than 30 inches in diameter and operate at pressures greater than 1000 psig. Therefore, we are defining a larger high consequence area for areas where there are larger high pressure pipelines. We propose to define these areas as follows:

An area where a pipeline lies within 1000 feet from a hospital, school, day-care facility, retirement facility, prison or other facility having persons who are confined, are of impaired mobility or would be difficult to evacuate, where the pipeline is greater than 30 inches in diameter and operates at an maximum allowable operating pressure (MAOP) of 1000 psig or greater.

As with the previously described areas, we are using a commercial database to help identify these areas.

In light of recent accident history, particularly, the explosion near Carlsbad, New Mexico, RSPA recognizes that the class location definitions may not cover all areas where a pipeline may pose a risk to the public. There are areas where people may not live, but they gather regularly for recreational or other purposes. We propose to define these areas as follows:

An area where a pipeline lies within 660 feet (or within 1000 feet where the pipeline is greater than 30 inches in diameter and operates at a MAOP of 1000 psig or more) where 20 or more persons congregate at least 50 days in any 12-month period. (The days need not be consecutive.) Examples of such areas include, but are not limited to, beaches, recreational facilities, camping grounds, and museums.

The 20-person number is used in the current definition of a class 3 location. We believe it is representational of the number of people that typically frequent a recreational area. This component of the proposed high consequence area definition should pick up most recreational areas or other areas where the public gathers on a regular basis. We have explicitly included camping areas to ensure that areas like those where the people were camping near the pipeline in Carlsbad will receive additional protection. Also, based on the C-FER model calculations, we propose to increase the area of the impacted zone from the current 300 feet to 660 feet (or 1000 feet for larger diameter pipelines).

As we previously mentioned, gas transmission operators are not currently required to maintain data on areas where people congregate near their pipelines. However, because operators are required to patrol their pipeline rights-of-way, they should have knowledge about these areas. This information should also be available from local public safety officials.

These proposed areas go beyond those specified in current regulations in the following ways:

1. A current Class 3 location includes buildings or areas where people congregate located within 300 feet of the pipeline. The proposed definition extends these areas from the pipeline out to 660 feet for most pipelines and out to 1000 feet for larger pipelines (those greater than 30 inches in diameter and operating at pressures greater than 1000 psig).

2. Current Class location regulations consider people located within 660 feet of a pipeline. The proposed definition includes an impact zone of 1000 feet from the pipeline for pipelines greater than 30 inches in diameter operating at pressures greater than 1000 psig.

3. Current Class location regulations include no explicit provision for facilities housing people with limited mobility. The proposed definition includes these facilities.

4. The proposed definition more explicitly references areas where people congregate near a pipeline, particularly, camping grounds.

We received no comment encouraging the inclusion of environmental areas as high consequence areas. In the proposed definition, we did not include sensitive environmental areas due to the highly localized impact of a gas pipeline rupture and explosion. Since a release from a gas pipeline accident is airborne, it is unlikely any major damage will occur to a threatened or endangered species. We received a similar response to our question on whether to include high traffic areas. We did not include such areas in the proposed definition because special attention is already given to these areas in the design and maintenance of pipelines near road crossings. Furthermore, the number of drivers that could be affected by a gas transmission pipeline accident is limited due to the highly localized effect of a gas release.

Regulatory Analyses and Notices

Executive Order 12866 and DOT Regulatory Policies and Procedures.

DOT considers this action to be a non-significant regulatory action under section 3(f) of Executive Order 12866 (58 FR 51735; October 4,1993). Therefore, the Office of Management and Budget (OMB) has not reviewed this rulemaking document. This proposed rule is also not significant under DOT's regulatory policies and procedures (44 FR 11034: February 26, 1979).

This proposed rule has no cost impact on the pipeline industry or the public, as it is only a definition. A regulatory evaluation is available in the Docket. The High Consequence Areas definition will be used in the forthcoming rulemaking on ``Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Operators)." When we issue that proposed rule, we will then fully evaluate all the associated costs and benefits.

Regulatory Flexibility Act

Under the Regulatory Flexibility Act (5 U.S.C. 601 et seq.) RSPA must consider whether a rulemaking would have a significant impact on a substantial number of small entities. This proposed rulemaking will not impose additional requirements on pipeline operators, including small entities that operate regulated pipelines. As this action only involves a definition, there are no cost implications, and thus, we determined it had no impact on small entities. Costs

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are likely to result once we issue requirements for actions that use this definition at a later date. RSPA will soon propose integrity management requirements for gas transmission pipelines in high consequence areas; at that time will examine the costs and benefits of that rulemaking. Based on this information demonstrating that this rulemaking will not have an economic impact, I certify that this proposed rule will not have a significant economic impact on a substantial number of small entities.

Paperwork Reduction Act

This notice of proposed rulemaking contains no information collection subject to review by OMB under the Paperwork Reduction Act of 1995 (44 U.S.C. 3507 (d)). Therefore, RSPA concludes the proposed rule contains no paperwork burden and is not subject to OMB review under the paperwork Reduction Act of 1995.

This proposed rule is simply a definition of high consequence areas. The definition will be used in the forthcoming rulemaking on ``Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Operators)''. RSPA will prepare a paperwork burden analysis for that proposed rule.

Executive Order 13084

This proposed rule was analyzed in accordance with the principles and criteria contained in Executive Order 13084 (``Consultation and Coordination with Indian Tribal Governments''). Because this proposed rule does not significantly or uniquely affect the communities of the Indian tribal governments and does not impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13084 do not apply.

Executive Order 13132

This proposed rule was analyzed in accordance with the principles and criteria contained in Executive Order 13132 (``Federalism''). This proposed rule does not propose any regulation that:

(1) Has substantial direct effects on the States, the relationship between the national government and the States, or the distribution of power and responsibilities among the various levels of government;

(2) Imposes substantial direct compliance costs on States and local governments; or

(3) Preempts state law.

Therefore, the consultation and funding requirements of Executive Order 13132 (64 FR 43255; August 10, 1999) do not apply. Nevertheless, in public meetings on November 18-19, 1999, and February 12-14, 2001, RSPA invited the National Association of Pipeline Safety Representatives (NAPSR), which includes State pipeline safety regulators, to participate in a general discussion on pipeline integrity. Since then RSPA held conference calls with NAPSR to receive their input before proposing a definition of high consequence areas.

Unfunded Mandates

This proposed rule does not impose unfunded mandates under the Unfunded Mandates Reform Act of 1995. It does not result in costs of $100 million or more to either State, local, or tribal governments, in the aggregate, or to the private sector, and is the least burdensome alternative that achieves the objective of the rule.

National Environmental Policy Act

We analyzed the proposed rule for purposes of the National Environmental Policy Act (42 U.S.C. 4321 et seq.) and preliminarily determined the action would not significantly affect the quality of the human environment. The Environmental Assessment of this proposal is available for review in the docket.

The Environmental Assessment (EA) considered the impacts of the proposed definition, in conjunction with future requirements of an integrity management rule. The EA found that the proposed definition by itself, did not by itself have any impact on the environment. When integrity management program requirements are issued which will incorporate the definition, there should be positive environmental benefits for the areas receiving additional protection.

However, because the environmental consequences from a gas release are limited, any impact is expected to be minimal. Therefore, the proposed definition of high consequence areas for gas pipeline integrity management will not have a significant environmental impact.

List of Subjects in 49 CFR Part 192

High consequence areas, Integrity assurance, Pipeline safety, and Reporting and recordkeeping requirements.

In consideration of the foregoing, RSPA proposes to amend part 192 of title 49 of the Code of Federal Regulations as follows:

PART 192--[AMENDED]

1. The authority citation for part 192 continues to read as follows:

Authority: 49 U.S.C. 60102, 60104, and 60108; and 49 CFR 1.53.

2. A New Sec. 192.761 would be added under a new heading of ``High Consequence Areas'' in subpart M to read as follows:

Subpart M--Maintenance

* * * * *

High Consequence Areas

Sec. 192.761 Definitions.

The following definitions apply to this section and Sec. 192.763:

High consequence area means any of the following areas:

(a) A Class 3 area as defined in Secs. 192.5(b)(3) and 192.5(c);

(b) A Class 4 area as defined in Secs. 192.5(b)(4) and 192.5(c);

(c) An area where a pipeline lies within 660 feet of a hospital, school, day-care facility, retirement facility, prison or other facility having persons who are confined, are of impaired mobility or would be difficult to evacuate;

(d) An area where a pipeline lies within 1000 feet from a hospital, school, day-care facility, retirement facility, prison or other facility having persons who are confined, are of impaired mobility or would be difficult to evacuate, if the pipeline is greater than 30 inches in diameter and operates at a maximum allowable operating pressure (MAOP) greater than 1000 psig; or

(e) An area where a pipeline lies within 660 feet (or within 1000 feet where the pipeline is greater than 30 inches in diameter and operates at a MAOP greater than 1000 psig) where 20 or more persons congregate at least 50 days in any 12-month period. (The days need not be consecutive.) Examples of such areas include, but are not limited to, beaches, recreational facilities, camping grounds, and museums.

Issued in Washington, DC, on January 3, 2002.

Stacey L. Gerard,

Associate Administrator for Pipeline Safety.

[FR Doc. 02-543 Filed 1-8-02; 8:45 am]

BILLING CODE 4910-60-P

3. AUDIT SECTION

A. Maintains headquarters and three district offices as follows:
Headquarters - William B. Travis Building
1701 North Congress, P. O. Box 12967, Austin, Texas 78701 Telephone (512) 463-7022
Ed Abrahamson, Assistant Director

Dallas District- 1546 Rowlett Rd., Suite 107, Garland, Texas 75043 Telephone (972) 240-5757; Fax (972)303-1897

Stephen Cooper, Supervising Auditor
Josh Settle, Auditor

Austin District- P. O. Box 12967, Austin, Texas 78711-2967 Telephone (512) 463-7022

Houston District- 1706 Seamist Drive. Suite 501, Houston, Texas 77008-3135 Telephone (713) 869-8425; Fax (713)869-3219

Mark Brock, Supervising Auditor
Dale Francis, Auditor
Margie Stoney, Auditor
Konata Uzoma

B. Gas Utility Tax, Annual Reports and Audit Reports

Questions relating to gas utility tax, annual reports and audit reports, call Shannon L. Miller at (512) 463-7022.

C. Available Information

Copies of company annual reports (1994 to present), as well as information relating to any of the above, A through C, are available for review at the William B. Travis Building, Gas Services Division, 9th Floor, 1701 North Congress. All requests for copies must be made in writing and should be addressed to the Audit Section. Copies will be provided for a fee, depending on the volume of copy work desired, allow a minimum of five days for completion of requests. Inquiries regarding copies should be directed to the Audit Section at (512) 463-7022, or Fax your request to (512) 475-3180**.**

4. REGULATORY ANALYSIS AND POLICY

A. Maintains the following office to assist you:

Headquarters - William B. Travis Building
1701 North Congress, P.O. Box 12967, Austin, Texas 78711 Telephone (512) 463-7164
Karl Nalepa, Assistant Director

B. Gas Utilities Information Bulletin

Published on the Commission's web site at: http://www.rrc.state.tx.us/divisions/gs/rap/rapbls.html.

C. Proposals For Decision

Published on the Commission's web site at: http://www.rrc.state.tx.us/divisions/gs/rap/pfds.html.

D. Tariff Filings

Questions pertaining to the filing of tariffs and/or quality of service rules should be directed to Kathy Arroyo, or Sandra Soto at (512) 463-7164.

E. Curtailments

Curtailment questions should be referred to Sandra Soto at (512) 463-7164. Curtailment reports made Monday through Friday, 8:00 a.m. to 5:00 p.m., should be made to (512) 463-7164. Curtailment reports made during hours other than those specified above and holidays, should be made to (512) 463-6788, (512) 896-3863 (digital pager), (512) 892-1772 or (512) 280-5949.

F. Compliance Filings

Questions regarding gas utilities docket compliance filing requirements should be referred to Jackie Standard at (512) 463-7164.

G. Complaints and Inquiries

All complaints and inquiries relating to the gas utility industry should be directed to the Regulatory Analysis and Policy section at (512) 463-7164.

5. HEARINGS AND LEGAL ANALYSIS

A. Miscellaneous

Anyone wishing to obtain copies of appendices to Orders appearing in Section 5 of this Bulletin should contact the Legal Division at (512) 463-7017.

B. Status of Pending Cases

The status of all pending cases listed in Section 3 of this Bulletin is for informational purposes only and is complete up to the time of printing of this Bulletin. For a more accurate status of pending cases, please call the Legal Division at (512) 463-7017.